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Cover Image: Siemens integrates cutting-edge technologies like artificial intelligence, Edge and Cloud computing, and Industrial 5G into the Digital Enterprise. Photo courtesy of Siemens.

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HP Industry Perspectives

H2TECH SOLUTIONS

H2-TECHSOLUTIONS.COM | MAY 18-19, 2021

H2Tech Solutions: Advancing hydrogen technologies

As announced in the January issue of *Hydrocarbon Processing*, Gulf Energy Information—publisher of *Hydrocarbon Processing* and *Gas Processing & LNG*—has launched the publication *H2Tech*. This publication will focus primarily on the latest technologies advancing the global hydrogen market. The magazine—to be published quarterly—will be a working technical journal for engineers and other professionals involved in hydrogen production and applications progress. *H2Tech* will focus on hydrogen technology on all spectrums—from green (via renewable energy) to blue (via natural gas with carbon capture) to brown (via coal gasification) and beyond.

To complement the publication, *H2Tech* will host a global, virtual technology conference called H2Tech Solutions, which will be held May 18–19, H2Tech Solutions will bring together engineers, technologists and managers working to advance fuel, chemical and industrial applications for hydrogen. The hydrogen technology conference will provide the latest advancements in the hydrogen industry. These include:

- Advances in hydrogen production technologies
- Midstream applications
- Chemical and industrial applications
- Infrastructure, transport and distribution
- Process/project optimization
- Safety and sustainability
- Fuel cell and transportation applications
- Power and utilities applications
- Hydrogen capital projects
- Storage
- Electrolyzer technology.

This free, two-day, online event will provide the global hydrogen industry with the latest advancements in how hydrogen is revolutionizing the global marketplace and providing a low-carbon/carbon-free product for fuels, chemicals and energy production.

For additional information or to submit an abstract for the event, visit H2Tech Solutions at www.H2-TechSolutions.com. For more information on the launch of the latest publication, *H2Tech*, to inquire about writing a technical article or signing up to receive the weekly newsletter, visit www.H2-Tech.com. HP

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SUBSCRIPTIONS

Subscription price (includes both print and digital versions): One year $399, two years $679, three years $897. Airmail rate outside North America $175 additional a year. Single copies $35, prepaid.

Hydrocarbon Processing's Full Data Access subscription plan is priced at $1,995. This plan provides full access to all information and data *Hydrocarbon Processing* has to offer. It includes a print or digital version of the magazine, as well as full access to all posted articles (current and archived), process handbooks, the *HPI Market Data* book, Construction Boxscore Database project updates and more.

Because *Hydrocarbon Processing* is edited specifically to be of greatest value to people working in this specialized business, subscriptions are restricted to those engaged in the hydrocarbon processing industry, or service and supply company personnel connected thereto.

Hydrocarbon Processing is indexed by Applied Science & Technology Index, by Chemical Abstracts and by Engineering Index Inc. Microfilm copies available through University Microfilms, International, Ann Arbor, Mich. The full text of *Hydrocarbon Processing* is also available in electronic versions of the Business Periodicals Index.

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Hydrocarbon Processing (ISSN 0018-8190) is published monthly by Gulf Energy Information, 2 Greenway Plaza, Suite 1020, Houston, Texas 77046. Periodicals postage paid at Houston, Texas, and at additional mailing office. POSTMASTER: Send address changes to Hydrocarbon Processing, P.O. Box 2608, Houston, Texas 77252.

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Publication Agreement Number 40034765 Printed in USA

Other Gulf Energy Information titles include: *Gas Processing™*, *Petroleum Economist©*, *World Oil®*, *Pipeline & Gas Journal* and *Underground Construction.*

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The tools advancing the HPI into the digital age

The HPI has been going through a digital transformation, increasingly adopting digital technologies to improve existing processes and structures to improve performance.

The following is an overview of some of the many digital technologies being adopted by the HPI.

Augmented/virtual reality (AR/VR). Process industries are benefiting greatly from the adoption of AR/VR. These technologies enable plant personnel to better train new and seasoned engineers for various field work, emergency situations, plant disruptions and/or maintenance functions. Wearable AR headsets enable the user to view specific data on various pieces of equipment. This is done by projecting digital images on the headgear's lenses. Maintenance personnel can simply look at any piece of equipment, and the headgear lens will display metrics such as flowrate, pressure, etc.

Artificial intelligence (AI). AI is being used in software and digital platforms to monitor equipment health and provide users with predictive analytics, which is decreasing equipment downtime, increasing reliability, providing actionable diagnostics for enhanced plant/unit performance and much more. AI can also boost energy efficiency, monitor plant emissions, optimize production and supply chains, and substantially increase margins and profitability.

Digital twins. A digital twin is a digital copy of a system, unit or process that can replicate real-life operations. Digital twin technology is helping provide companies the ability to simulate operations and configurations on units—to conduct "what if" scenarios—without affecting real-time operations. The technology is crucial in providing operators with a virtual "best path forward" for unit efficiency, as well as a beneficial asset for training personnel.

Drones and autonomous systems. Drones and autonomous systems (e.g., robots) can be used for safety purposes. For example, drones can be flown around process equipment to provide high-resolution video and/or images to personnel on the ground or within a control room. These images can provide inspection and maintenance personnel with evidence needed to create work orders.

Autonomous vehicles/bots, embedded with AI, have also been used to monitor safety hazards (e.g., corrosion) in processing plants and drill rigs. These AI-embedded inspection bots can learn to "talk" to each other and communicate issues regarding potential safety hazards that need maintenance work.

Cybersecurity. The use of new digital technologies has also opened the HPI to additional cyber threats. This predicament has led organizations to invest in additional cybersecurity technologies to protect critical infrastructure and company/employee data. These cyber-barriers (e.g., firewalls, encrypted data) are crucial to keep plants, companies and workers safe.

Plant design, engineering and construction. Finally, new digital technologies are aiding the capital construction industry. Digital tools (e.g., software, AR/VR, modeling systems) are enabling EPCs to better design, engineer and configure individual units, plant infrastructure or whole grassroots facilities, as well as expansions, unit integration, commissioning, supply chain, logistics and so much more.

Takeaway. New technologies are transforming the way plant owners/operators, EPCs and service/supplier companies are optimizing operations. This issue's Special Focus is devoted to the advancement of these digital technologies and how they are propelling the HPI to increased reliability, profitability, safety and sustainable operations. HP

INSIDE THIS ISSUE

D. DICKSON, Deloitte Services, Stamford, Connecticut

Are chemical companies ready for the future of work?

The COVID-19 pandemic has caused significant, short-term disruption to the chemical industry, potentially leading to long-term impacts. Employment in the chemical industry was also significantly impacted by the COVID-led slowdown. Based on statistics from the U.S. Bureau of Labor, between December 2019 and December 2020, the chemicals industry experienced job cuts of nearly 17,500, or 2.1% of the entire workforce. During this period, the industry lost 37,700 production jobs but added 20,200 non-production jobs, including researchers and scientists.

Furthermore, the drop in oil prices threatened to erode the cost advantage of U.S. petrochemical producers who use cheap and abundant NGLs as feedstock. With the dual effects of cheaper naphtha and lower international natural gas prices, production economics continue to support ethane-based crackers in the U.S., keeping them competitive vs. their European and Asian rivals. However, this advantage could be threatened by an unexpected and sustained surge in natural gas prices due to factors such as supply and demand imbalance and a significant and persistent decline in oil prices. Timelines for several U.S.-based petrochemical projects have been affected as companies reevaluate end-market demand.

The pandemic and market volatility have helped to accelerate some workforce trends already underway, such as the adoption of automation, digitization and more remote work, creating greater demand for workers to fill jobs in key areas, such as data analytics and cybersecurity. For example, there is growing demand for employees with research and development (R&D) experience, such as scientists and engineers and areas that help drive sustainability; however, one of the primary challenges for the chemical and refining industries is recruiting enough employees with these critical skills. In addition, the chemicals industry workforce is aging, with as many as 40% of industry workers eligible to retire in the next five years, according to the U.S. Bureau of Labor Statistics.

A further challenge is that existing employees with digital skills are at risk of migrating to other industries, such as technology and pharmaceuticals, where the prospects of career growth may seem to be brighter. The downturn also seems to be having a knock-on effect on a few fast-growing specialty chemicals businesses that compete with relatively stable businesses—such as life sciences—in sourcing talent in the growing material informatics and advanced materials sciences space. We examine these trends using the framework of work, workforce and workplace:

- **Work.** The nature of work and job roles are changing. The need for continuous improvements in production processes is driving changes in the talent landscape, including shifts in job roles. More than 40% of employees have R&D and technical servicing experience. Scientists and engineers compose about 10% of the industry workforce. The share of jobs with analytical, information technology and technical competencies is growing.
- **Workforce.** While automation and the use of advanced digital technologies are driving productivity, they are also leading to changes in workforce composition, increasing the need for a workforce with more advanced chemical engineering, data science and digital skills. Digitalizing operations or announcing net-zero long-term plans could boost interest by new graduates. Transformative work, well-defined career paths and agile working models could be critical to allowing chemical companies to attract new workers and to leverage and disseminate the knowledge of tenured employees.
- **Workplace.** A dramatic change is occurring in the chemical industry workplace largely due to two key factors: globalization and interconnectivity. Globalization is the ability to manufacture and distribute chemical products across the world in a well-controlled manner through enterprise software and enabled systems. Interconnectivity is the ability to access, interact with and work with a skilled workforce around the world. Moreover, the COVID-19 pandemic is forcing companies to change how and where employees work. Many organizations have already adjusted to working remotely and have restructured their infrastructure to support work-from-home capabilities for their employees. In terms of innovation, value is migrating from the traditional R&D departments of chemical companies to material informatics platforms. Until recently, the process of discovering and developing new chemicals has remained primarily lab based. Many new companies that lie at the intersection of material science and computer science (i.e., material informatics) are reimagining their R&D departments towards open digital platforms.

Today's changed environment has given chemical companies the much-needed "why" to transform themselves and find new ways to reclaim their earlier appeal. How can these companies adapt? According to a recent industry workforce report[1], there are four levers of transfor-

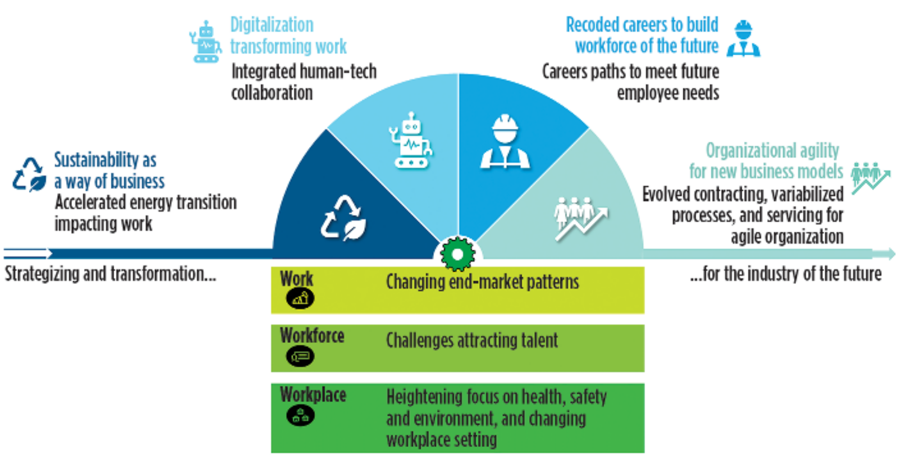

FIG. 1. Chemical companies can use the four levers of transformation to prepare for the future.

mation that could push companies into the future: energy transition, integrated human-machine collaboration, recoded careers and organizational agility (**FIG. 1**).

These levers may seem difficult at the start, as all initiatives to change an organization or its culture are challenging initially. Once management engages with a transformation and empowers its employees to drive and shape the transformation, the pathway to transformation will likely be widely embraced.

Sustainability. The consequences of the pandemic seem to have reinforced the call for long-term decarbonization and transition to cleaner energy sources.[2] The chemical industry and its served end-markets are evolving along with the growing emphasis on sustainability, and new industrial ecosystems (e.g., electric mobility) are emerging. This could create new opportunities for chemical companies to develop advanced material solutions and services to serve unique needs and capture more added value to other industries. This could mean more than $1 T/yr of additional value.[3] However, the opportunities arising from a focus on these new areas present a challenge to the industry in terms of hiring new employees with the right technical skill set, as well as imparting these new colleagues with the organization's institutional knowledge of environment, social and governance (ESG) issues.

Digitalization. The COVID-19 pandemic appears to have brought a greater urgency in accelerating companies' digitization efforts to unlock new operational gains. Digitally enabled disruptions in major end-markets—such as transportation, computers and electronics, semiconductors, agriculture, and housing and construction—can affect business models across the industry. The chemicals industry workforce is under increased pressure to reduce time to market given the emergence of new entrants, increasing bargaining power of existing downstream players and the power of digital technologies.

Recoded careers. In addition to a renewed focus on attracting skilled new employees, companies should develop the existing workforce. For example, some companies are enabling scrum teams of data engineers, data scientists and technical experts to work together to solve internal and customer problems.[4] They can also transform typical hierarchical structures with cyber-physical collaboration—such as reimagined collaborations or super teams (humans and intelligent machines working together fruitfully), which could provide transformative insights and solutions.[5] Companies can devise unique programs with a broader objective to grow the existing workforce so that they can add value to future business plans. In addition to formal training, companies have been providing diversified exposure to business leaders by moving them to cross-functional roles every few years to enhance their value and competencies.

Perhaps the final challenge is how to engage and retain a tenured workforce. Could the looming brain drain from retiring employees be turned around by building a stronger cross-generational pairing to leverage the knowledge of experienced colleagues? Establishing unique programs (e.g., reverse mentoring) can foster more collaboration and two-way engagement between senior executives and young professionals.

Organizational agility. Organizational agility, driven by its four levers (portfolio, assets, processes and commercial), can help the chemicals industry increase efficiency by building a more flexible asset base relying on more diverse feedstocks managed by increasingly digitalized and automated processes. The industry has an opportunity to cut costs and become more agile by making people, processes and technologies more conducive for the post-COVID future.

On the way to transforming their organizations, leaders may have to constantly probe their plans and course correct to deliver added value. They should continually assess hard or even unfavorable business decisions. Continual self-assessment can go a long way in generating a resilient company. After all, the endgoal in tackling these questions is simple: building a chemical company of the future by making bold choices today for the work of tomorrow; expanding job canvases of the workforce by creating redesigned, cyber-physical teams and fungible roles; and embracing a digital workplace culture that remains open to future innovations.[6] HP

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[1] Dickson, D., *et. al.,* "The future of work in oil, gas and chemicals," Deloitte Insights, October 2020, online: https://www2.deloitte.com/us/en/insights/industry/oil-and-gas/future-of-work-oil-and-gas-chemicals.html

[2] Dickson, D., *et. al.,* "Oil, gas and the energy transition," Deloitte Insights, August 2020, online: https://www2.deloitte.com/xe/en/insights/industry/oil-and-gas/oil-gas-energy-sector-disruption.html

[3] Yankovitz, D., *et. al.,* "Digital opportunities for chemical enterprise: Creating lasting value," Deloitte Insights, 2018, online: https://www2.deloitte.com/content/dam/Deloitte/us/Documents/manufacturing/us-manufacturing-digital-opportunities-for-chemical-enterprises.pdf

Complete literature cited available online at www.HydrocarbonProcessing.com.

DUANE DICKSON has more than 38 yr of business and consulting experience in senior leadership positions in major industrial and health care products companies. He is a Vice Chairman and Principal in Deloitte Consulting LLP's Energy Resources and Industrials industry group, as well as the U.S. Oil, Gas and Chemicals sector leader.

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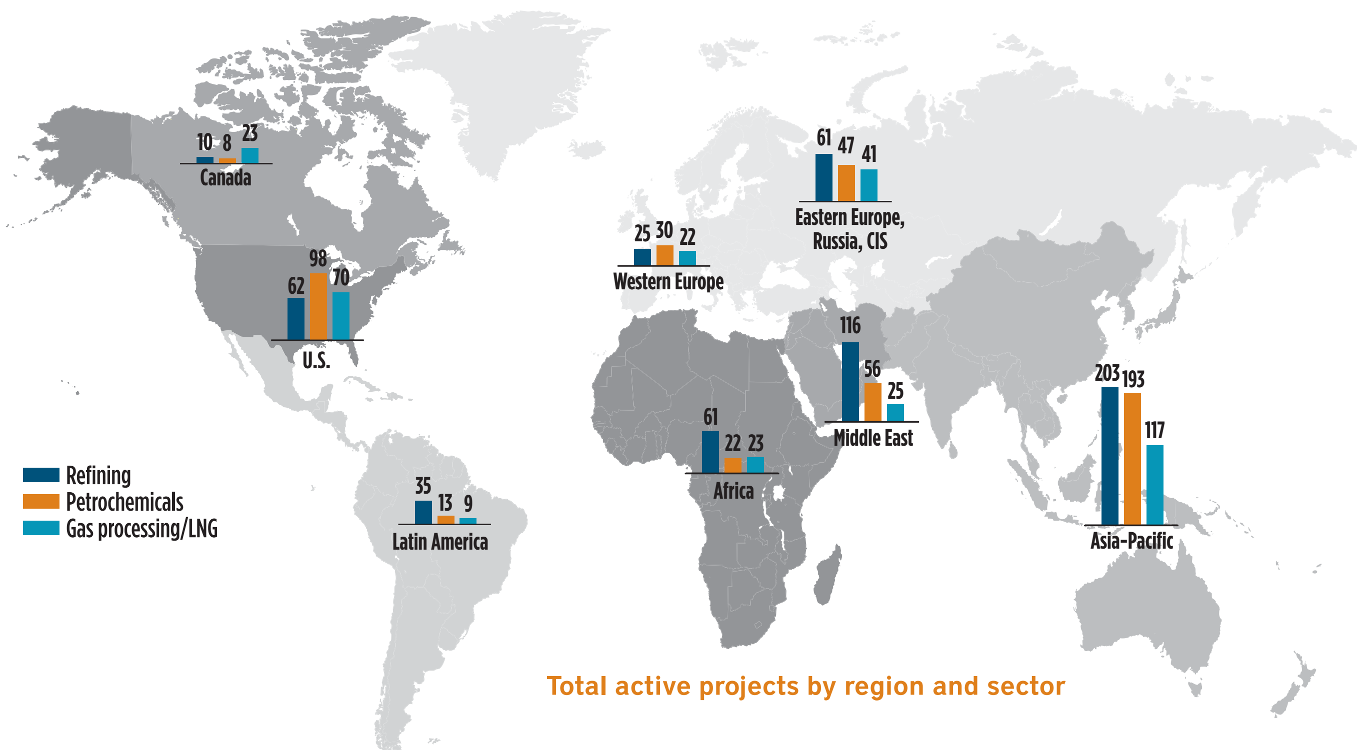
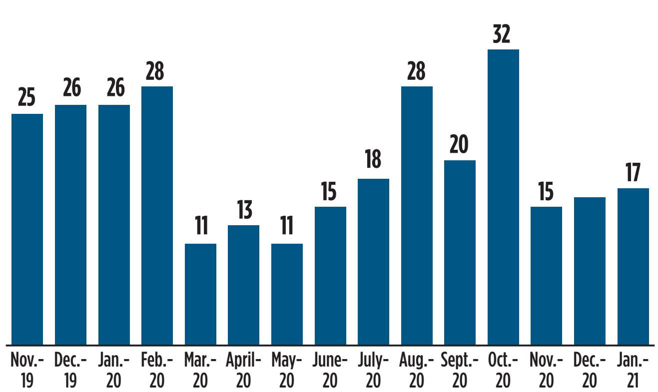
HP Global Project Data

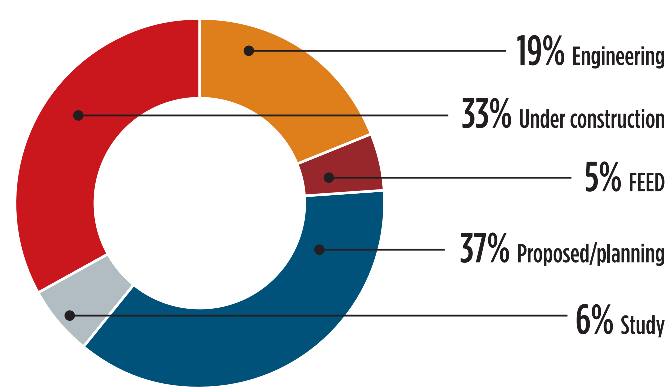
Hydrocarbon Processing's Construction Boxscore Database is tracking nearly 1,400 projects around the world. The Asia-Pacific region accounts for 37% of active projects market share, followed by the U.S. (17%) and the Middle East (14%). Approximately 67% of active projects are in preconstruction phases. Projects within the planning/proposed phase represent the largest market share for active projects (37%). More than 40% of projects in the planning/proposed phases are within the Asia-Pacific region. HP



Total active projects by region and sector



New project announcements, November 2019–January 2021



Active project market share by activity level

MIKE RHODES, MANAGING EDITOR
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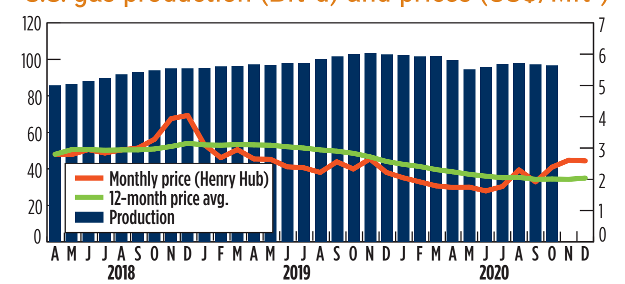
HP Industry Metrics

Global refining margins showed mixed results. Refineries have returned from the autumn peak maintenance season, showing a slight rise in available spare capacity globally. The U.S. saw improvement in transport activity during year-end holidays, but refinery intakes remain around 2 MMbpd below y-o-y levels. European markets weakened, affected by stronger crude prices amid seasonal weakness. Asia refining margins suffered mostly in the bottom of the barrel due to a decline in fuel oil requirements from the utilities sector. HP

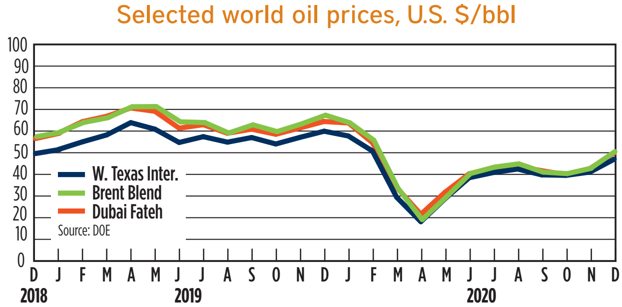
An expanded version of Industry Metrics can be found online at HydrocarbonProcessing.com.

U.S. gas production (Bft^3d) and prices ($US\$/Mft^3$)

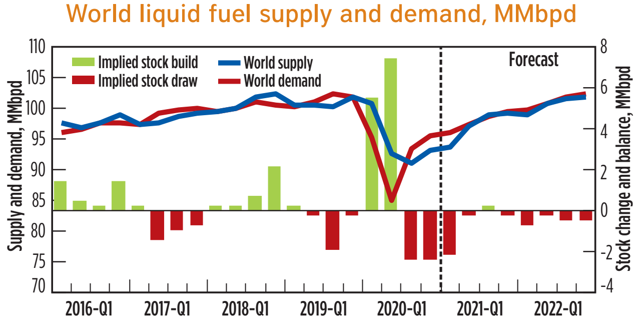


Production equals U.S. marketed production, wet gas. Source: EIA.

Selected world oil prices, U.S. $/bbl

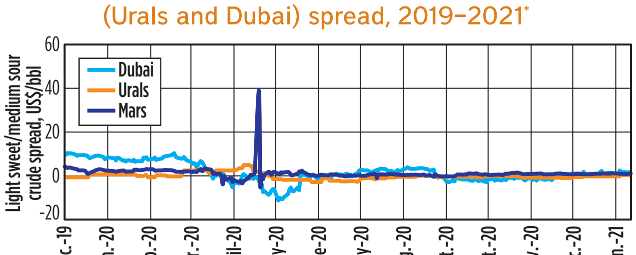


World liquid fuel supply and demand, MMbpd

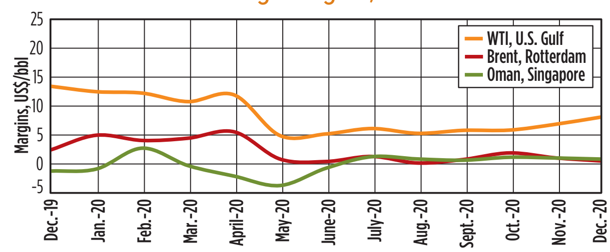


Source: *EIA Short-Term Energy Outlook*, January 2021

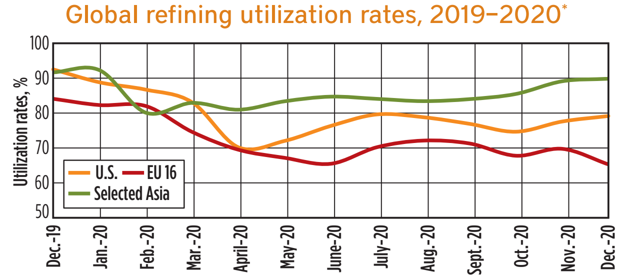
Brent dated vs. sour grades (Urals and Dubai) spread, 2019–2021*



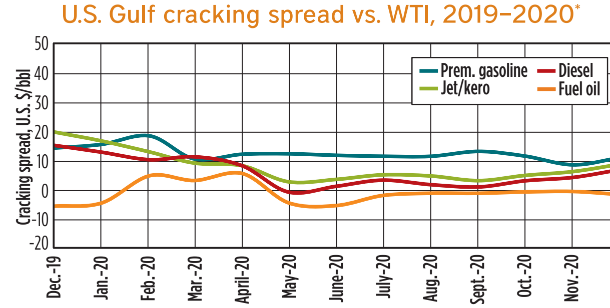
Global refining margins, 2019–2020*



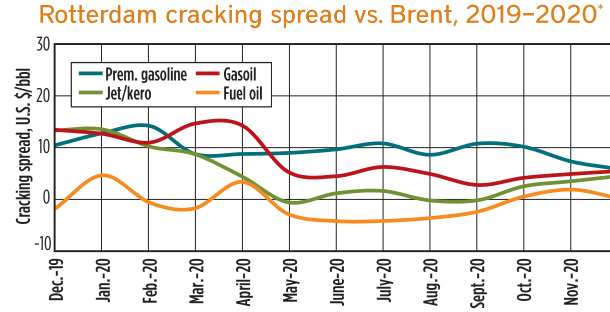
Global refining utilization rates, 2019–2020*



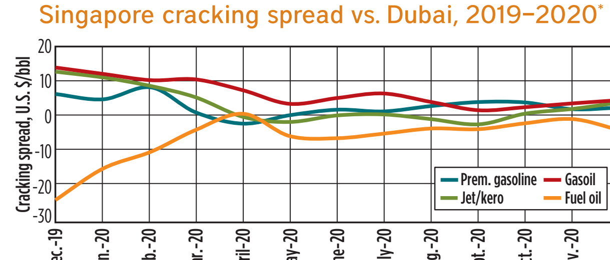
U.S. Gulf cracking spread vs. WTI, 2019–2020*



Rotterdam cracking spread vs. Brent, 2019–2020*



Singapore cracking spread vs. Dubai, 2019–2020*



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Plan startups wisely and involve SMEs

DE, a retired former colleague of mine, recounted his experience as an expert witness for ABC in litigation against XYZ. (Note that I picked the letters A through M for the plaintiff's side; N through Z are assigned to the defendants.) Defendant XYZ was an overly optimistic, perhaps moderately negligent, supplier of bulk raw material to ABC, the plaintiff. The plaintiff's profitability depended on the uninterrupted flow of raw material from XYZ, which was the manufacturer of malfunctioning turbomachines that were clearly involved. The startup was delayed, and the unforeseen consequential losses for ABC were far-reaching.

ABC had hired DE as its expert machinery reliability witness. In his role, DE had to explain to the litigants what ailed the big process machines and why these, or similar large compressors and steam turbines (**FIG. 1**), are known to operate well elsewhere. DE and his contributing colleague, FG, uncovered little or no data on the success or failure of whatever actions XYZ's machinery engineers had taken to get satisfactory performance from the machines at XYZ. However, the plaintiff's team did not uncover any documents indicating how XYZ's owners had determined labor requirements to support equipment startup efforts.

Be this as it may, DE and FG began poring over thousands of documents after being engaged by the law firm representing ABC. To make a long story short: XYZ had failed to meet its contractual obligation to deliver bulk raw material to ABC because the very large turbomachinery trains failed during startup.

The two parties settled out of court after it became clear that XYZ had revamped its major machinery trains and missed the startup deadline by a significant period of time. The company had been warned well ahead of time that its fast-track startup schedule was unrealistic. Unsurprisingly, defendant XYZ had encountered several troubles stemming from mechanical problems with a reputable manufacturer's machines. The dry gas seals in its compressors had failed because no one had paid attention to the steam turbines' slow-rolling requirement. General organizational disarray was evident; organizational disarray is often caused by too many cooks spoiling an entire meal.

No access to management. For hydrocarbon processing plants to thrive, subject matter experts (SMEs) must have direct access to upper management. If their findings and concerns are being filtered by the various layers between persons empowered to make risky decisions and those enabled to offer sound experience-based advice, the tracks are set for a collision with reality.

"As a matter of fact," said DE a year later, "I was offered up to XYZ's executive VP, along with another machinery SME, to do a one-day cold-eye review of this fiasco. The VP was sent to the facility to determine if corporate headquarters would authorize the plant to attempt a restart. ABC was also in a bad way due to XYZ not delivering bulk raw material per their contract, and the issue even drew regional newspaper headlines."

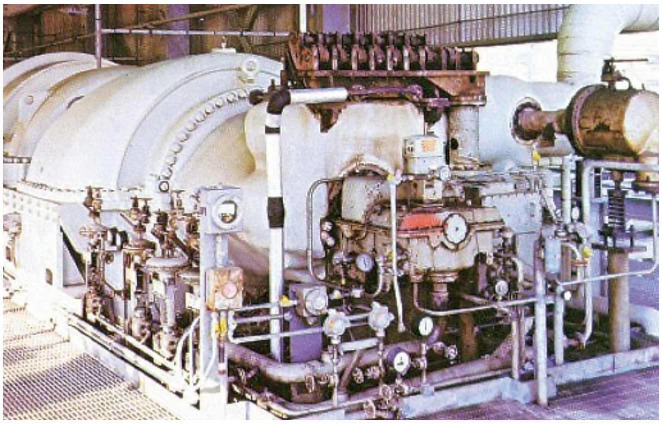

FIG. 1. Large steam turbine driving a turbocompressor.

DE recalled that the seal gas piping for the dry gas seals had been fabricated from carbon steel and had not been cleaned after installation. All of the dry gas seals failed on startup. The compressor manufacturer made its share of mistakes and could never deliver the unrealistic schedule outlined by XYZ. It was suspected that the schedule had been determined using a proposal made by KLM, an experienced vendor that had issued a bid not favored by XYZ. Instead, XYZ had bought machines from NOP and then expected its staffers to perform like KLM.

The various defendants also had internal problems. Although not quite obvious, the reviewing SMEs sensed that there had been dissent regarding the schedule. Regrettably, their cultures did not allow for the voicing of divergent opinions and, during the discovery phase of litigation, DE and FG found no potentially "career-limiting" remarks. Yet, their overall impression of a startup gone wrong was supported by an entry from NOP's field service engineer: "I don't feel the love…"

The two reviewers were left with the impression that everybody towed the line, and one of the two is now putting the finishing touches on a 300-plus page book on the topic of how to implement a successful startup. It will offer a great number of detailed startup checklists to those who are willing to read and listen. HP

HEINZ P. BLOCH resides in Montgomery, Texas. His professional career commenced in 1962 and included long-term assignments as Exxon Chemical's Regional Machinery Specialist for the U.S. He has authored or co-written more than 800 publications, among them 23 books devoted to reliability improvement. A recent one, titled, *Fluid Machinery: Life Extension of Pumps, Gas Compressors and Drivers,* was published in June 2020 by DeGruyter (Berlin, Germany). It describes many equipment-related steps of interest to reliability professionals.

The importance of digital twins and cloud-based services

ANDREW MCCLOSKEY is the CTO and Head of R&D for AVEVA. In his role, he is responsible for product development, including execution excellence, built-in quality and security, and fostering innovation across the company's global R&D efforts. He is a member of AVEVA's Executive Operating and Strategic Leadership Teams responsible for AVEVA's Engineering Business P&L, which includes process design, plant engineering and design, shipbuilding, procurement, fabrication, construction and operator/enterprise training. Prior to this, he was Executive R&D Leader for the Schneider Electric Software Business. He joined the group (formerly Invensys Plc.) in 2006 as Head of R&D for the Simulation Products team.

Prior to Schneider Electric, Mr. McCloskey was the Lead Engineer working on Space Shuttle's guidance systems for the U.S. National Space Program; Product Development Manager at two successful startups that resulted in multi-million-dollar acquisitions; and Director of Engineering for the Toshiba Mobile Division, where several new innovative offers were developed and drove double-digit growth for the company.

Mr. McCloskey holds several technical patents and under his leadership his teams have created more than 100 new patents. He earned a BS degree in aerospace engineering from California Polytechnic University Pomona. He attended USC for graduate studies, and has taught university level courses in software development.

Hydrocarbon Processing spoke with Andrew McCloskey, Chief Technology Officer and Head of R&D at AVEVA, about how digital twins and cloud-based services are used, their benefits and challenges, security issues, etc., as related to the downstream oil and gas, refining and petrochemicals industries.

HP: What are digital twins and how is AVEVA using them to facilitate its customers' digital transformation initiatives?

McCloskey: Digital twins are virtual replicas of a physical object or system. Extended reality technologies enable manufacturers to create a complete digital twin of their processes and assets, which allows them to respond to unexpected events quickly and efficiently, and reduce unplanned shutdown time that can cost businesses millions of dollars each year. Additionally, digital twins can incorporate real-time process data with current economic conditions, expediting the decision-making process for operators.

Our customers in the downstream oil and gas, refining and petrochemicals industries have faced significant challenges to their efficiency, sustainability and profitability due to COVID-19—deploying digital twins has boosted their resilience and reduced costly downtimes. For example, with this technology, operators can create the representation of an actual piping and instrumentation diagram (P&ID), map each equipment object to a detailed engineering database, and 3D model build and test the dynamic stimulation early in the process design.

HP: You mentioned the impact of COVID-19 on the downstream petroleum industry. In the current, largely remote working environment, how do digital twins support workers in this industry and enhance refinery and petrochemical plant operations?

McCloskey: The benefits of deploying digital twins in workforce training are multifold, and include familiarizing employees with an industrial site, bolstering safety protocol training and enabling interactive field operations and maintenance. For example, using a tablet device or Microsoft HoloLens, employees can view an augmented overlay of a physical asset and access step-by-step procedures for maintenance or training purposes. This, in turn, generates precise operating information that enables teams to improve performance and accelerate pace.

AVEVA has also been helping oil and gas industry clients ensure operational continuity during COVID-19 by prioritizing their remote visibility. For the worker that is now offsite, the digitalization gap poses an immediate issue, as what could be easily observed while onsite must either be captured and conveyed by the skeleton crew onsite or via sensors. If remote work becomes the new normal in the long term, the need to digitalize the closed-loop process to capture higher levels of fidelity—which, in effect, represents a process twin—is made even more clear.

Increased information sharing between internal stakeholders is another way in which digital twins enhance refinery and petrochemical plant operations, with key performance indicator (KPI) data projected across process and overall plant production. Digital twins accelerate the operational excellence of plants by supporting the entire engineering lifecycle, from unleashing a continuous improvement of operations to optimizing process and control design by comparing capital vs. operating costs.

Refinery and petrochemical plant operators today are demanding improved

flexibility and agility, as well as the ability to collaborate seamlessly from their technology deployments, and AVEVA is responding to this need.

HP: How does the current volatility in oil prices impact your customers? What are the challenges associated with using digital twins?

McCloskey: The current macro operating environment for oil and gas companies has accelerated the need to optimize manufacturing operations and improve performance to protect profitability.

Ensuring the accuracy of data is critical to success. In response, we are increasingly seeing these producers invest in their own cloud-based data platforms for current and future capital projects, operations and maintenance as part of their digital transformation projects. By and large, this shift is due to the fact that accurate data, kept in one place, ensures the reliability of a digital twin's output and the efficiency of operations throughout the asset's lifecycle. Through 3D visualization, engineering data can tell customers the type, size, connection source, operational background and location of equipment installed on a plant site. This data is generated in capital projects, from new plant builds to brownfield revamps and retrofits, and forms the backbone of the digital twin.

Lowering total cost, time and risk in capital projects are the major challenges associated with implementing digital twins. While each industrial environment brings different challenges, the petrochemical industry is well-positioned to adopt digital twins. In fact, early adopters of digital twins have predominantly been the continuous process and certain discrete repetitive industries, which have higher levels of automation. Due to their highly instrumented environments, these industries can more easily minimize essential workers onsite and shift many operational functions offsite using high-fidelity digital twins.

Undoubtedly, COVID-19 has forced every industry to reexamine its work processes and digital twins offer a framework to reimagine the new world of work.

HP: What does the future refinery/plant look like?

McCloskey: The future refinery/plant will likely put sustainability at the forefront: managing energy usage and costs, optimizing process yields, and reducing or eliminating safety-related incidents will contribute to this goal.

The industrial world is progressing through the transformation cycle that retail and finance experienced 10 yr ago. We are working with leading companies in energy to increase operational efficiency, unify their data and connect their teams to realize Industry 4.0. Companies like BP are using us to accelerate decision making from weeks to hours and optimize profitability throughout their value chain.

The pandemic has accelerated our conversations because everyone is under pressure to cut OPEX and minimize CAPEX and risk. Software can materially affect how companies transform and streamline their operations, and our customers are working with us to lead them through this period of change. HP

O. PLOWMAN
Actenum Corp., Vancouver, British Columbia, Canada

Optimize plant turnarounds with AI-powered software

How much time and costs can be saved by scheduling with an AI-powered solution? The numbers are staggering. While plant shutdowns are a necessary part of life, they can either be a positive activity that increases productivity or a negative one if the shutdown exceeds its deadline and goes beyond the budget.

Plant shutdowns are often required by federal and state governing agencies to prevent accidents and ensure that the plant is running within stated regulations. Time is money, so site-specific plans are key when implementing a safe and effective shutdown. Additionally, many facilities are inspected during shutdowns and if issues are uncovered, the shutdown is extended and costs are increased.

Plant shutdown activities can last from a few weeks to even months. These activities require a combination of labor and equipment that is well-orchestrated to complete all tasks in as short a time as possible and get operations back online in a timely matter at the least cost. AI-powered software allows managers to schedule and optimize thousands of activities and hundreds of resources automatically and rapidly, and quickly re-sequence the schedule if any changes occur—all of which save significant time, and time is money, of course.

Everyday challenges. A maintenance manager's typical day involves scheduling required maintenance work by assigning it to the available maintenance crews and other resources. Over a typical week, a manager may have to schedule hundreds of these maintenance activities, some of which may be critical. What if the software used to build and manage the maintenance schedules is out of date or unsophisticated? If this is the case, a lot of manual work will be done, and because there is no time to carry out the required analysis of the schedule, many important questions will go unanswered.

For example, how will maintenance activities impact production? Can we reduce non-productive time and still complete the work on time, and how much money will that save? If crew members are out or have medical issues, what will be the impact on the schedule? Should work on specific equipment be moved up to lessen the impact on the plant production? What is the best response to unanticipated events, such as a breakdown or outage, that we cannot control?

These questions emphasize the need for maintenance managers to have a higher degree of scheduling automation at their fingertips and to use software's predictive capabilities to create an effective and efficient schedule of maintenance work orders.

Accelerating schedule creation and management. Recently, a heavy industrial plant utilized a proprietary AI-powered scheduling software[a] to help schedule a 4-d shutdown at their plant. To ensure they made the right decision, the plant shared their schedule in Microsoft Project and asked if it could be improved upon. As a response, the AI-powered scheduling solution was utilized to schedule tasks, materials and people in an optimal way. The built-in, AI-powered optimizer rapidly evaluates all available options and selects the sequence of activities that best meets user-defined constraints and production targets. The scheduling software[a] was quickly loaded at the plant in just one day, enabling the shutdown schedule to be optimized. Additionally, the software eliminated the need for multiple applications or spreadsheets and time-consuming manual calculations.

Once it was up and running, the software did the heavy lifting of initial schedule creation (FIG. 1)—searching the set of activities, resources, sequencing/timing combinations and preferences/policy requirements to assemble a schedule in far less time than would be required using a more manual approach. What might take days or weeks to complete manually was done in minutes. Ongoing schedule

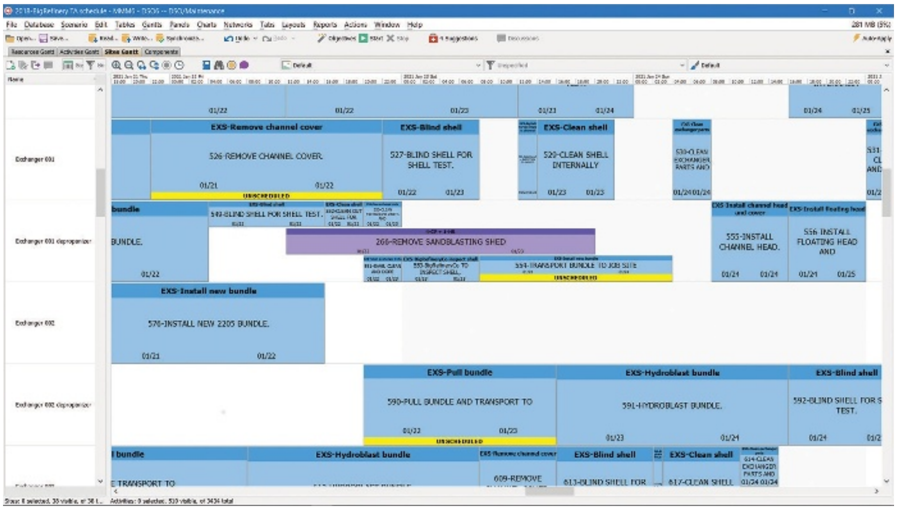

FIG. 1. The AI-powered scheduling software[a] delivered predictable performance by aligning schedules with business rules and constraints, enabling everyone in the organization to benefit from a complete, single-source view of operations.

management was greatly simplified using automatic scheduling logic.

The AI-powered software automatically schedules and optimizes thousands of activities and hundreds of resources and quickly re-sequences the schedule if any changes occur (e.g., an on-the-job injury). By linking a schedule to key metrics, the software can also provide immediate insight into how changes to that schedule will impact costs and production goals, ensuring the schedule is aligned with business objectives.

The software took all constraints into account to eliminate idle time. It analyzed all personnel involved and their tasks, then automatically optimized the schedule so that people were working and not waiting. In addition, the software identified how resources could be optimized and revised the schedule accordingly. With everything and everyone maximized in the schedule, resources were used to their fullest with activities unfolding in the optimal order to ensure fewer interruptions in the process.

One schedule to view, enhancing collaboration. The AI-powered scheduling software[a] delivered predictable performance by aligning schedules with business rules and constraints, enabling everyone in the organization to benefit from a complete, single-source view of operations. The plant also used companion software that is a web-based schedule visualization and reporting tool (**FIG. 2**). This tool provided access to published maintenance schedules and associated data for all team members, from an internet-enabled device, and incorporated Gantt chart and tabular views of schedule information so everyone was viewing one single source of truth. The tool also allowed for input from front-line workers for more informed decision-making.

Eliminating 366 days of idle time. More importantly, by optimizing activities for the plant shutdown, the software provided a 4% improvement in the reduction of idle time, which in turn eliminated 366 days of idle time. In terms of financial savings, considering a cost of $500/d multiplied by 366 days, the plant potentially saved $183,000 in just three days. Because shutdowns can take place as many as six times per year, the potential savings can exceed $2 MM. The software helped align

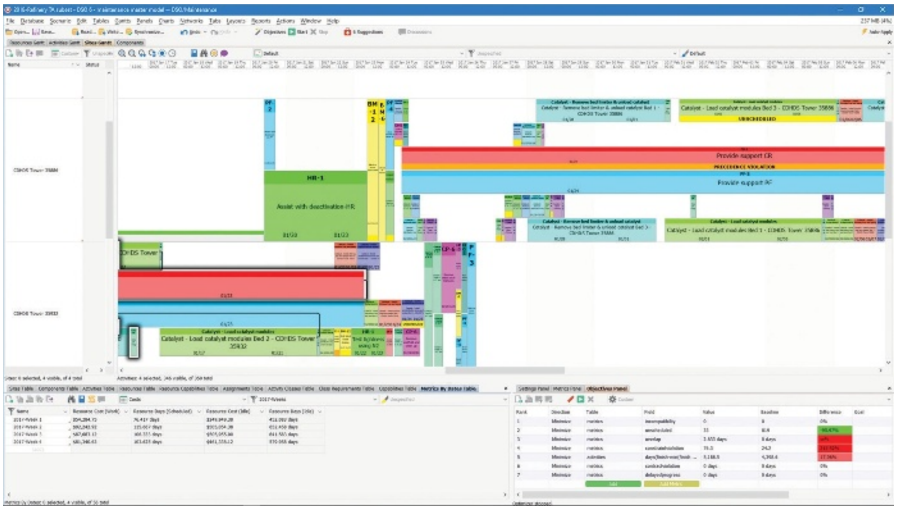

FIG. 2. A web-based schedule visualization and reporting tool provides access to published maintenance schedules and associated data for all team members.

the client's operational decisions automatically with business goals to maximize their return on investment through intelligent and responsive resource allocation.

Benefits beyond schedule optimization. In addition to optimizing schedules, the proprietary AI-powered scheduling software can optimize against cost resources. The scheduler can immediately see how their decisions would impact costs using "What if?" scenarios and advanced analytics. For example, what would the cost savings be if a higher cost resource of a welder at $180/hr was swapped for one at $120/hr? During turnarounds, an extra day can mean the difference between making or losing millions of dollars. AI-powered software can achieve this by adding different sets of resources to reach a faster time-to-production date.

Interactive capability puts users in control. To enable complete user control over a schedule, AI-powered software provides an interactive capability so that the user can adjust and adapt any schedule to accommodate organizational preferences. In a typical scheduling situation, a scheduler will use the software to generate a "first cut" solution automatically and will then manually manipulate this solution to incorporate preferences and to determine their impact. The scheduler can also lock the schedule for a specific time horizon (such as "up to 180 days from today") and use the optimizer to rearrange the sequence of activities outside the locked time horizon to meet a specific objective.

Plant shutdowns are one of the most critical times in the operation of a plant. The revenue lost by shutting down a plant can amount to a significant portion of an annual budget and affect the plant's financial future in either a positive or negative way. However, when done efficiently, a shutdown can boost both plant reliability and revenues. AI-powered scheduling software provides a single solution that improves capital efficiency and reduces costs by ensuring the right resources, assets and people are in the right place at the right time and quickly re-sequences the schedule if any changes occur. Simply stated, it is a proven way to optimize the plant shutdown schedule and maximize financial savings. HP

NOTE

[a] Actenum DSO/Maintenance

OWEN PLOWMAN is the VP of Business Development at Actenum Corp., where he blends his software technical skills with knowledge of the oil and gas industry to advance Actenum's product capabilities and address customer challenges effectively. He has worked in the IT industry for 41 yr. Prior to joining Actenum, he spent 14 yr at Oracle Corp. Canada Inc., in a variety of management positions in sales consulting, technical support, marketing and professional services. He left Oracle to act as an independent consultant to small and mid-sized software companies. Mr. Plowman began his career writing commercial software in 1979. After completing his university studies in molecular biology and computer science, he was employed by Meta Systems Canada (an Ontario software startup), where he led development team efforts and consulted on projects for Canadian and U.S. government agencies and defense contractors.

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Using 3D metallic printing for manufacturing refinery pump impellers

Additive manufacturing (AM), also known as 3D metallic printing, is identified as one of the game-changing technologies in recent years for the oil and gas industry. Although the nonmetallic AM industry has progressed significantly, metallic additive manufacturing for the oil and gas industry is still in the early development phase. Various technologies have been developed, or are being developed, to allow manufacturing of metallic spare parts.

Saudi Aramco, a major oil producer, is collaborating with several AM-leading companies to evaluate this technology and capitalize on its benefits, where applicable. This article documents the collaboration between Saudi Aramco and Siemens Energy to manufacture and deploy the first 3D metallic-printed pump impeller, for use at Saudi Aramco's Riyadh refinery.

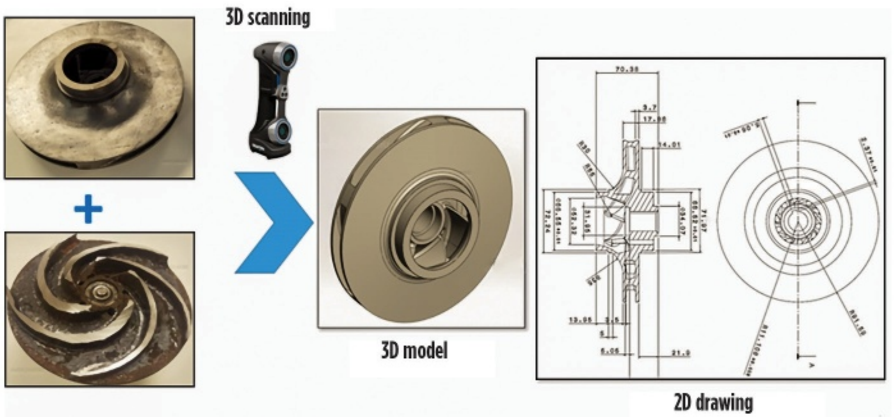

FIG. 1. Drawing development process.

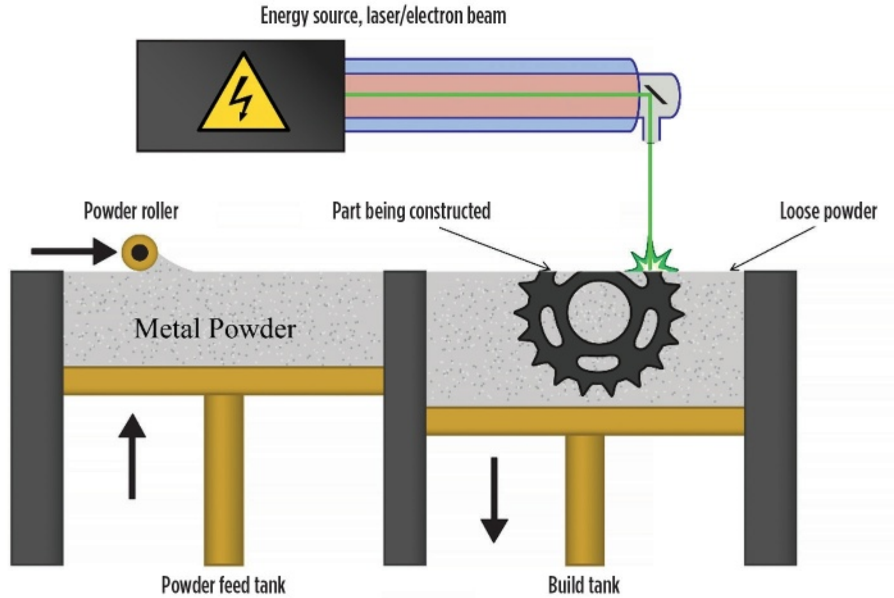

FIG. 2. Powder bed fusion process. Source: 3DEO.

Trial part selection.

As the target for this trial was 4 mos–6 mos of field testing, the team started the part selection exercise for a component used in rotating equipment that will be in continuous operation for the duration of the trial. This would ensure that the part was subjected to dynamic load, which is more severe than static loads. In addition, the part should not have any major impact on the plant safety and operation if it fails during the field test. Several equipment items and parts were considered, and a final decision was made for conducting the trial on an impeller for a water circulation pump with the parameters specified in **TABLE 1.**

Part dimensional measurements.

Since the pump impeller has complex geometry, it was necessary to do a 3D scan of the impeller to obtain its overall shape. In addition, since the selected impeller is a closed design with small internal passages, it was not possible to obtain the ge-

TABLE 1. Parameters for trial for an impeller for a water circulation pump

Parameter	Value
Pump type	Horizontal overhung
Liquid	Water
Differential head, m	65
Flowrate, m^3/hr	13
Motor rating, kW	7.5
Original impeller material	Cast iron
Impeller diameter, cm	18.3
Part failure mode	Corrosion

ometry of the internal passages. As such, the external geometry of the impeller was obtained by scanning a new impeller that was available at a Saudi Aramco warehouse. The internal geometry was obtained by scanning an older, damaged impeller after machining away its front shroud.

Finally, a 3D model was developed for the impeller based on the two 3D scans. A 2D drawing was also developed for identifying the required machining tolerances and dimensions. The 3D model and the two drawings were shared with the Siemens Energy AM center to manufacture the impellers for this trial. FIG. 1 summarizes the 3D model development process and shows the 2D drawing.

Note: The 3D model was modified by the AM center to add extra thicknesses to all machined surfaces. This included filling the keyway and adding material on the impeller wear rings landing areas, bore and outer diameter.

Impeller manufacturing. Since the selected pump is not in a hazardous application and has a standby spare pump, the supply scope was limited to the manufacturing of one impeller with test coupons on the same build bed. If the part was very critical or if the part failure presented a safety risk, then the scope would have included the manufacturing of one additional impeller to be used for destructive testing.

The AM technology used for manufacturing this impeller is the laser-based powder bed fusion (PBF) technology. Powder bed fusion is an additive manufacturing process in which thermal energy selectively fuses regions of a powder bed, as demonstrated in FIG. 2. PBF methods use either a laser or an electron beam to melt and fuse material powder together.

Although the nonmetallic additive manufacturing industry has progressed significantly, metallic additive manufacturing for the oil and gas industry is still in the early development phase. Various technologies have been developed, or are being developed, to allow manufacturing of metallic spare parts.

The use of laser-based PBF technology has various other names, such as selective laser melting (SLM), direct metal laser melting (DMLM) and laser powder bed fusion (LPBF).

The PBF technology is the most mature AM technology available for manufacturing complete parts. This technology is typically limited in size based on the printer bed size, which is typically less than 400 mm × 400 mm × 400 mm. This size continues to expand, as some printers have a higher build volume than this typical range. In addition, this technology has some limitations in terms of material. Typically used materials are copper, aluminum, 300 series stainless steel, tool steel, cobalt chrome, titanium and Inconel. A market search shows no or very limited development on the use of this technology for manufacturing parts from cast iron, carbon steel or duplex stainless steel. As the existing impeller material was cast iron and suffered from failure due to corrosion, the 3D printed impeller was manufactured from 316 stainless steel material. This upgraded material was considered acceptable since the main risk, which is galvanic corrosion, was found to be of no concern due to the low total dissolved solids in the process water.

As part of the manufacturing process, the Siemens AM center studied and simulated the buildup process of the impeller to minimize the needed external supports and to eliminate any support inside the impeller internal passages, as shown in FIG. 3. This is one of the most challenging manufacturing processes, requiring significant experience and technological know-how. It should be noted that the same model was shared with several other AM part manufacturers that rejected the work due to their inability to eliminate internal supports. The main issue when adding internal supports is the inability to machine them away due to limited accessibility, thereby rendering the manufactured impeller useless.

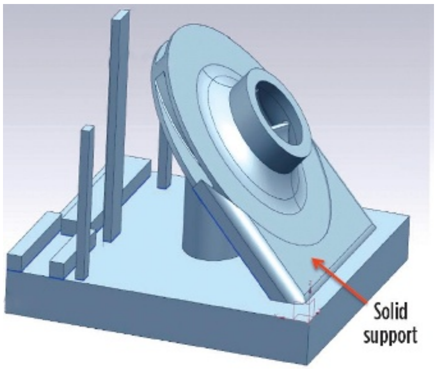

FIG. 3. Printing arrangement for the impeller and the test coupons.

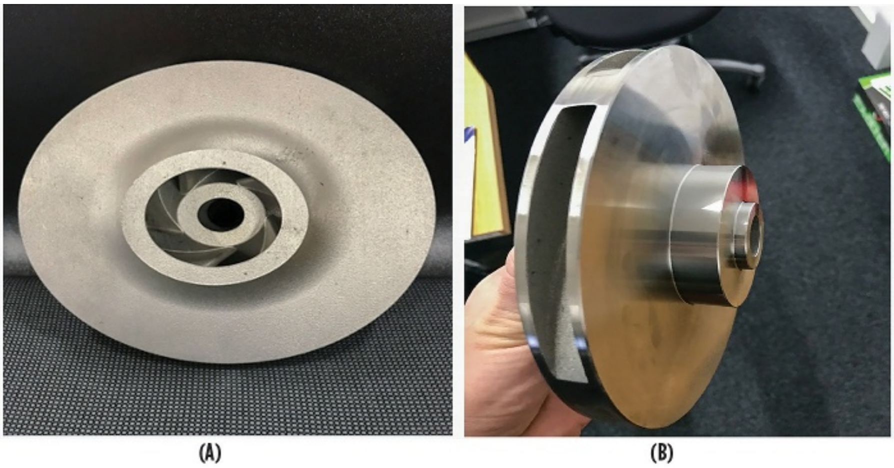

FIG. 4. Manufactured impeller after printing (time = 64 hr) (A); and after post-processing [(no heat treatment (B)].

The impeller, shown in **FIG. 4,** was printed at a Siemens AM facility. Test coupons were printed together with the impeller, using the same technique and parameters for the examination of material structure and mechanical properties (e.g., corrosion, tensile strength). The actual impeller printing duration was 64 hr. The impeller was then removed from the printer for post-processing, which included the removal of supports and final machining. The Siemens AM manufacturing process for 316 stainless steel did not require any post-printing heat treatment.

This trial showed the ability of AM to significantly reduce the manufacturing time for parts. The entire new part assessment and manufacturing can be reduced to 4 wk–6 wk, while printing of a previously completed part can be managed in a few days. It should be noted that the cost of an AM part tends to be higher than the original equipment manufacturer cost. This is why AM should be considered when the part is needed in urgent cases, or if the end user is interested in reducing its warehouse spare parts inventory.

AM technology and part qualification. The qualification for any part manufactured by AM typically involves the qualification of the AM production facility and the qualification of the part. At present, no international standards exist that provide mandatory requirements for AM qualification. However, several industrial standards have been developed, or are in development, to provide good guidance on how to qualify an AM production facility and an AM part. Examples of these standards are DNVGL-ST-B203, which address laser-based powder bed fusion (BPF-LB) technology and wire arc additive manufacturing (WAAM) technology.

The AM production facility qualification typically consists of three main sections:

1. Qualification of the printer, which includes the qualification of the printing machine and associated auxiliaries, as well as the qualification of the printer operators
2. Qualification of the printing process, which typically includes significant development and testing to find the correct printer parameter settings that produce the desired material properties without manufacturing defects
3. The qualification of the facility quality system (e.g., by meeting ISO 9001).

On the other hand, the qualification process for an AM part can have significant variation depending on the part criticality. It can involve destructive testing of manufactured parts, manufacturing and testing of test coupons produced with the AM parts, nondestructive testing for the parts or mere visual inspection of the part.

Part testing. The trial included nondestructive testing for the impeller to verify its integrity through several tests, including visual inspection, radiographic testing and penetrate testing. In addition, the manufactured testing coupons were sent for material and tensile strength testing. The test coupons were printed in both horizontal and vertical arrangements, as shown in **FIG. 3.** This is typical for PBF technology, since the printing methods build up the part in the vertical direction, which leads to some differences in the mechanical properties between horizontal and vertical testing coupons.

After passing nondestructive testing, the impeller was installed in the pump and went through a 5-mos field test where the pump was kept in continuous operation. This field test included a pump performance evaluation that showed the pump performed per its original design and within acceptable vibration limits. Finally, the impeller was removed for inspection after completing the test. Visual inspection and liquid penetrant testing were conducted, and the impeller was found to be in excellent condition. The team decided to return the impeller to the pump for permanent plant use.

Takeaway. This article documents the successful utilization of AM to manufacture a pump impeller. This installation was part of the work being done by Saudi Aramco to obtain experience with this game-changing technology in the oil and gas industry. With 3D printing, companies can benefit from a significant reduction in manufacturing time and consequently improve critical parts delivery. This technology also presents a great opportunity to transform from physical inventory in warehouses to a digitalized warehouse that can simplify supply chains and optimize investment in spare parts. HP

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VLADIMIR NAVROTSKY is Chief Technology Officer (CTO) of Industrial Application Service for Siemens Energy and a Senior Principal Key Expert in gas turbine design and aftermarket. He holds a PhD in mechanical engineering from Moscow Physical and Technical University. Dr. Navrotsky has more than 30 yr of professional experience in international organizations such as the Central Institute of Aviation Motors in Russia, ABB in Sweden, ALSTOM in Switzerland and Siemens. As an employee of Siemens for more than 20 yr, he has held several management positions and was appointed Gas Turbine Fleet Director and Global Service Technology and Innovation Manager (CTO) in 2007. In 2010, he was also promoted to Senior Principal Key Expert in addition to these responsibilities. In 2015, Dr. Navrotsky was awarded the honor of Siemens Top Innovator.

CORIE ALLEMAND, GLOBAL LEADER FOR OIL AND GAS
Stratus Technologies

Edge computing in the COVID-19 recovery period

CORIE ALLEMAND is the Global Leader for Oil and Gas with Stratus Technologies. He is responsible for the go-to-market strategy and driving the global business. For more than 25 yr, he has held various roles, including maintenance technician and services lead for electrical and automation assets on multiple onshore and offshore pipelines, prior to moving into various sales and leadership roles. He spent the last 9 yr as part of the Siemens Oil and Gas Solutions Team, where he supplied power electronics to global drilling companies, topside power solutions for offshore production, subsea connectivity solutions, as well as various pipeline solutions and applications to the midstream market. Mr. Allemand holds a BS degree in business management and an MBA.

As the COVID-19 pandemic forces businesses to rethink standard operations, many are considering how technologies can help in the upcoming period of recovery. Looking ahead, edge computing will play a significant role in helping organizations foster a nimbler and more efficient operating environment. *Hydrocarbon Processing* was pleased to discuss these subjects with Corie Allemand, Director of Oil and Gas Business Development at Stratus Technologies.

HP: Do you predict that the increased adoption of technology will last beyond the pandemic?

Allemand: Yes, I do think technology will be one of the main drivers in leading the oil and gas industry back to profitability. This is the third downturn I have experienced in my career, and each time technology has played a role in redefining normal operations. As the industry returns to providing the energy our world requires to function, technology will be engaged in new ways to explore how and where the industry can optimize processes, reduce recurring costs and increase visibility of existing complex operations.

HP: As the oil and gas industry grapples with COVID-19, what role does edge computing play in helping these players through this "survival mode" phase?

Allemand: Edge infrastructure plays a critical role in the movement toward a nimbler and more efficient operating environment in oil and gas. The industry is dealing with historical events that are forcing businesses to rethink standard operations. The ability to expand the vision of employees into remote resources through real-time applications can enhance asset management and efficiency. These tools are designed to create increased visibility and insight into operations and require reliable edge infrastructure to ensure data is always available. Edge computing creates the platform for an increased view into asset performance and the ability of analytical tools to assist with predicting asset behavior.

HP: How can edge computing increase plant/rig safety, especially as facilities face staff shortages and limitations due to the pandemic?

Allemand: Edge computing can play an important role in safety and the protection of people and the environment by supporting real-time data collection and processing of measurements where they are created. The ability to process data with more speed creates an environment that can reduce equipment failures and the resulting maintenance requirements when facing the dilemma of limited personnel.

HP: How does edge computing increase the reliability of systems?

Allemand: Edge computing enables real-time analysis of operations data to designed simulation, which is the basis for the digital twin. These real-time simulations running comparatively to actual operating conditions can reveal issues such as inefficiencies, early indication of degraded process performance of assets, or potential risks related to equipment or the environment. The use of data captured in real time and processed at the edge is critical to the performance of predictive maintenance tools. These tools can help to minimize unplanned downtime, which equates to millions of dollars in savings over the course of a given year.

HP: How can oil and gas organizations move forward with planned DX initiatives as they now face financial hardship?

Allemand: Oil and gas organizations should increase their focus on digital as they reassess their current operating profile. Digitalization in the oil and gas space is focused on doing more with less. As the industry finds itself in a low-cost environment having to assess G and A costs, they should look at what the expansion of digital technologies can do to expand the capabilities and view of their personnel. Digital tools to increase efficiencies through real-time data analysis of operating conditions can enhance the capabilities of operations personnel. Edge platforms enable predictive maintenance of critical equipment, allowing for optimization of routine maintenance costs. Real-time analysis of expensive assets can prevent unexpected downtime of critical assets—a multimillion-dollar unplanned expense for oil and gas organizations. HP

C. LAU, Schneider Electric, Houston, Texas

Reduce OPEX and improve sustainability through digital energy optimization strategies

Oil and gas companies are looking for quick ways to reduce OPEX amid the pandemic and oil and gas market crises. Initiatives to improve sustainability are further intensifying this challenging environment. Energy cost is about 30% of variable and labor costs, the second largest expense following feedstock cost. Energy optimization is a key opportunity to reduce energy cost and lower emissions.

Digital transformation solutions can accelerate the return of energy optimization investments. By implementing digital energy optimization strategies, an average-size refinery (200,000 bpd) or petrochemical plant can improve profitability by an estimated $15 MM/yr–$30 MM/yr and reduce carbon dioxide (CO_2) emissions by 500,000 mtpy–900,000 mtpy: the equivalent to taking 100,000–200,000 gasoline-fueled cars out of service.

Visualization and monitoring. Visualization and monitoring can be simple and effective solutions to reduce energy costs. Integrating various sources of energy data and displaying them in key performance indicators (KPIs) that operators can relate to—and how their actions can impact the company's overall objectives—enforces accountability. An often overlooked basic solution is automation loop tuning and performance monitoring. Automation loop performance monitoring ensures that each control loop is performing to its designed performance. A South African chemical company was able to reduce its steam cost by $3.6 MM/yr utilizing real-time accounting and visualization solutions.

Energy management and utilities modeling. Using proven software technologies, such as advanced regulatory control and advanced process control (APC), can reduce variance of operational conditions. Once the process is achieving stable operation, the application of real-time optimization allows the plant to run close to its optimal target. The benefits include energy conservation, minimizing material consumption, maximizing throughput and reducing product quality variance. A Japanese refinery reported a 5% reduction in energy cost using a real-time optimization strategy. The largest Indian refinery reported a savings of $7.2 MM through better visualization and $5 MM via real-time optimization.

Variable speed drive. A variable speed drive (VSD) is a simple energy-saving solution that provides quick payback. By using VSDs vs. on-off switch direct across the line motor starters, up to 50% of energy cost can be saved. Thousands of pumps function in an average refinery, and hundreds of fans in a liquefied natural gas (LNG) plant, so energy costs can add up quickly. Pumps and motors are often oversized, so more energy is being consumed than is required. Most new VSDs also have smart condition-based monitoring capabilities that help improve asset availability. The author's company's remote electrical asset monitoring solutions helped a U.S. petrochemical plant detect undersized VSDs and malfunctioning transformers that caused premature aging, allowing them to avoid unscheduled plant shutdowns.

Digital twin. Digital twins are a hot topic today, but what would generate more return on investment (ROI) is using one digital twin model for the entire lifecycle—from design to simulation, to engineering and commissioning, to operator training, to operations and maintenance. Digital twin for equipment monitoring is an online asset monitoring strategy based on the design vs. actual concept. It assists operating sites to improve performance by

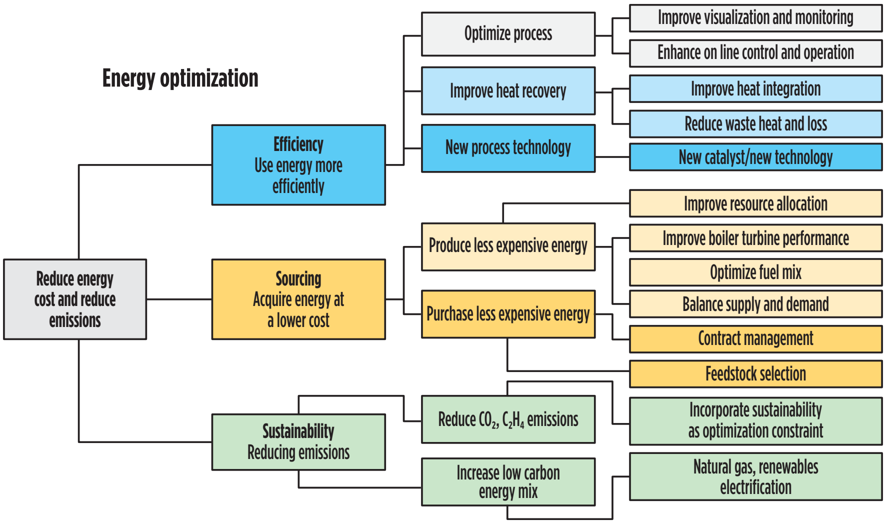

FIG. 1. Manage the three elements of energy efficiency, sourcing and sustainability by adopting a strategic comprehensive plan to help reduce energy cost and lower emissions.

leveraging the digital twin prediction feedback to the operation staff. Digital twins can be developed for process units or assets such as compressors, exchangers, fire heaters, pumps and electrical equipment.

Unifying power and process. Power and automation are two key digital elements in digital transformation, so it only makes sense to integrate power and automation that are traditionally separated. By adopting this unifying concept through the entire lifecycle of a plant—beginning with incorporating power data into the digital twin from design to build to operations to maintenance—profitability and sustainability can be improved dramatically. By integrating energy data with process data into a unifying process automation system, operators can visualize asset health and energy efficiency; conduct rapid diagnostics of motors, pumps, fans, MOV and electrical assets problems through sequence of events; diagnose problems; and resume productions in minutes vs. days.

Energy sourcing. Strategically sourcing energy can reduce energy cost. For example, the author's company can help customers make smarter purchases, whether it is improving efficiencies or increasing renewable energy content. The company has helped more than 6,000 clients globally and managed $30 B in portfolio spending to date.

Active energy management. Traditionally, companies manage the three elements of energy efficiency, sourcing and sustainability in silos (FIG. 1). A better way of approaching this is by adopting strategic comprehensive planning to help reduce energy cost and lower emissions. The author's company's energy experts can help improve energy forecasting and purchasing decisions, and benchmarking energy KPI goals. An energy management software[a] that is based on a global data management platform collects vast data sources and integrates them into one single source of energy and sustainability information depository.

Value chain optimization. Enterprise-wide value chain optimization is based on enterprise visualization and unified planning and scheduling. By optimizing feedstock purchases and production schedules, companies can make faster decisions and improve asset performance. Companies can track production costs, energy cost and materials in real time as they move through the supply chain. A major Middle East oil and gas company asserts that it has realized a $1-B benefit since implementing a value chain optimization solution only a few years ago.

Microgrid optimization. Microgrid optimization is optimized energy management from multiple distributed energy sources, interconnected loads, controlled as a single entity, operating in parallel with the grid or in an intentional island mode. Hospitals and airports are utilizing microgrid to improve their resiliency and energy efficiency. The microgrid strategy is not a new concept to oil and gas companies. Plants have been optimizing energy sources and trade-offs using steam, fuel and electrical grid energies. Refineries have been utilizing cogeneration technology for a long time, while some plants are selling power back to the grid, and most plants have fast load-shedding capabilities. What will be new for oil and gas companies is incorporating renewable energies as part of the energy management system. Some onshore well pads and offshore platforms are already incorporating solar and offshore wind energies. We may see microgrid applications for downstream oil and gas soon.

Energy as a service. This is a new concept of operating companies outsourcing energy to a third-party company to design, build, own, operate and maintain with no capital investment. One of the major benefits is the shifting of CAPEX to OPEX, especially when capital budgets are constrained. The idea behind this is that companies can choose to focus on their core business in oil and gas by leasing energy. HP

NOTES

[a] EcoStruxure™ Resource Advisor

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Data historian-based machine condition monitoring

Machine condition monitoring has been playing an increasingly important role in industrial asset healthcare for many years. More machines are being monitored—not just the critical ones—and more comprehensive and in-depth monitoring techniques are employed. Although vibration analysis theory, the primary basis of condition monitoring, has not changed much in the last 50 yr, monitoring techniques have evolved considerably. This is partly due to experience, monitoring system technology and data science. Industrial Internet of Things (IIoT) technologies and strategies have been changing the information landscape drastically in many industries, but has it also affected machine condition monitoring?

Machine condition monitoring systems and their limitations. Condition monitoring systems (CMSs) offer various levels of insight into machine healthcare but all have a common purpose: to reduce both downtime and lifecycle costs of running and maintaining plant machinery. This is done by detecting and diagnosing machine potential failure modes at an early enough stage of development so focused maintenance can be cost-effectively scheduled ahead of time without interrupting the machine's production capacity. The CMS does not perform process control or other enterprise functions, so it is more or less a stand-alone system consisting of its own sensors, signal conditioning unit, CM server and database.

Many of the systems are still based on proprietary servers with restricted license access, so in many cases, the user becomes completely dependent on the CMS provider and their expertise. If the CMS specialists are unavailable for an urgent machine diagnostic issue, the option of using a remote third-party analyst can be challenging simply due to restricted CMS access. Even if the CMS data was available for third-party analysis, measurement configuration information regarding signal filtering and processing would be most likely unknown, thus complicating the task of doing a reliable diagnosis.

The disadvantages of a proprietary CMS are not just limited to restricted data access for analyzing a specific machine fault. It also makes it difficult to get an overview of the general machine healthcare awareness of a specific monitored machine or fleet of machines, especially if some of the data is monitored by other systems. Correlating process data and monitoring data from other CMSs to vibration measurements is an important means for improving the reliability of fault detection and diagnostics for all operating conditions. Although many CMSs can import process data, this is often done at the discretion of the CMS supplier at the time of installation and cannot always be easily changed when new process information is available.

Lastly, there is the question of security and economy of scale of installing, running and maintaining a proprietary system installation within the IT infrastructure. As the user interface is different from one system to the next, CMS training also must be individualized.

With all the advancements of CMS technology, is there a solution to resolve these issues?

Data historian enhances plant and machine healthcare. Distributed control systems (DCSs), supervisory control and data acquisition (SCADA) and programmable logic controllers (PLCs) are used by industry to control production to a high level of reliability, safety and efficiency. These systems represent the pinnacle of information and control technology. Regarding data storage, historically speaking, a DCS typically stored data for only a week or so, which was considered to be more than sufficient from a control perspec-

FIG. 1. An example of a proprietary diagnostic tool offered by a monitoring system supplier.

tive, but insufficient from a maintenance point of view. The data historian concept consequently emerged to fill this gap. With advanced data processing and storage capability, the data historian extended DCS/PLC capability by offering much more insight into production reliability, quality and performance for the entire plant, as well as for the individual machines.

Moreover, the historian provided tools that can work extensively with the data. These tools are continuously being developed but presently include functionality for historical and current machine performance visualization, navigation for finding data, event handling of anomalies, notification of events, reporting, and even calculated measurements for specialized monitoring and Boolean logic for generating alarms.

For all practical purposes, the data historian seemed like the perfect solution match for integrating a CMS. Both systems depend on big data and use much of the same information processing tools. The integration, however, has been slow. Why?

Machine condition monitoring in the data historian. In the beginning, the data historian data was limited to the DCS/PLC plant-wide process control data, whereas the CMS stand-alone systems were focused on machine vibration data. This was initially a technology-based decision since raw vibration data and spectral data required a data sampling rate and resolution that far exceeded that required for process data. An even greater obstacle for the migration of CMS data into the historian was the question of how to manage vibration diagnostic expertise.

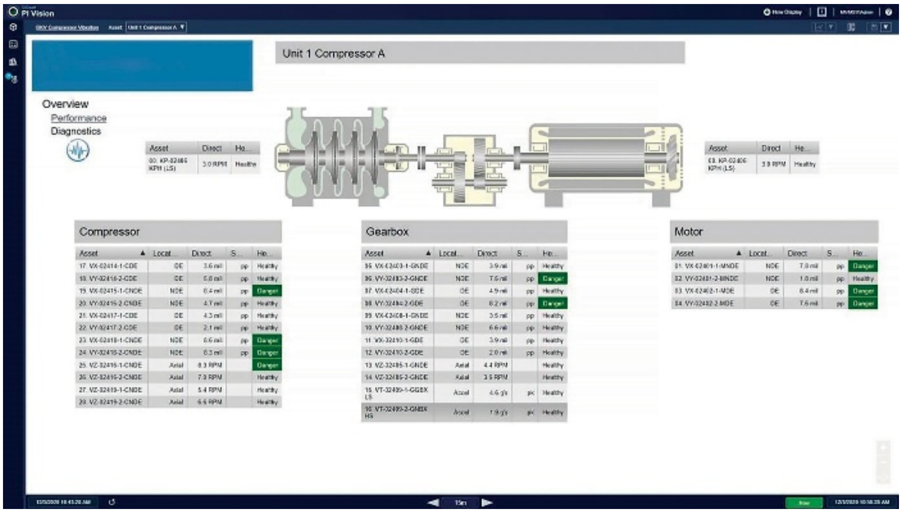

FIG. 2. An example of a data historian view screen showing the health status for a compressor train. The circled vibration signal in the upper left-hand corner is a link to the diagnostic tools shown in **FIG. 1.**

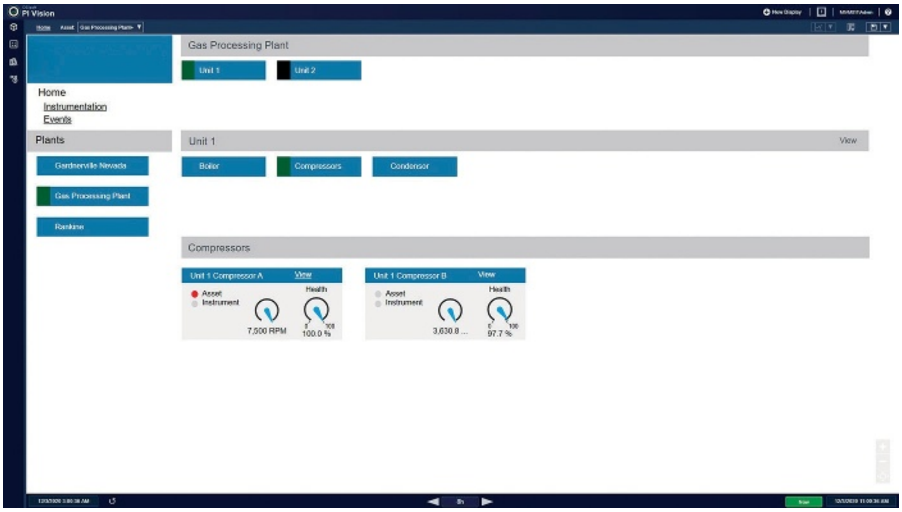

FIG. 3. An example of an overview plot in the data historian. By clicking on the Unit 1 Compressor A, **FIG. 2** appears.

Much of the work in a data historian is simply to detect and trend measurement amplitude changes to identify process changes or developing machine faults. A CMS also does this, but a major function of the CMS and the specialists who work with the system is to also identify and localize the detected fault, determine the nature and severity of it, and estimate lead-time to service. This is fault diagnostics, a specialist area for vibration analysts, where most who work in the data historian space are traditionally not trained in. Although many vibration measurements, such as the bandpass for running speed (1x) and the second and third harmonics (2x, 3x), can easily be stored, detected and trended in the historian. Expertise is needed to evaluate the relationship of this data to perform proper diagnostics.

A CMS specialist (inhouse or from the CMS supplier) is needed to look at and diagnose the data stored in the historian. Moreover, the CMS specialist utilizes diagnostic tools in the system that are not normally available in the historian, as shown in **FIG. 1.** Therefore, even if many vibration scalar measurements can be stored, detected and trended in the historian, most of the diagnostic work is actually done in the CMS itself. Therefore, many have questioned the actual benefits of storing the vibration scalar values in the historian rather than in the CMS server.

Because of the diagnostic expertise barrier, condition monitoring functionalities that could otherwise be done in the historian remain in the traditional CMS, namely data storage, visualization, navigation, event handling, notification and reporting. This makes the CMS an isolated world of its own. Is any work being done to change this?

Historian-based condition monitoring. Recent events have been changing the coexistence between the historian and CMS. A new generation of CMS suppliers within the data historian environment have begun to challenge the lofty positions of the traditional CMS suppliers. Most of the newer supplier condition monitoring functions are now done in the historian itself, including data storage.

However, for the diagnostic functionality part of the system, such as diagnostic algorithms, specialized measurements and plots, this is still separated from the historian. However, even this has been improved. Diagnostic plot functions and their corresponding measurements (**FIG. 1**) can now be accessed directly from the historian user interface with a single mouse click, as shown in **FIG. 2.**

One of the most important advances, however, is that it is now possible to store high-resolution vibration time waveforms in the historian database. This was the initial stumbling block for CMS-data historian integration; it has finally been removed so all data can now be stored in the historian, both scalar and dynamic values. This means raw data in the historian can be re-processed by service providers either as a second opinion, or in the case where the normal diagnostic specialists are unavailable. There is still no standardized way of associating measurement configuration information to the raw data stored in the historian, but this is expected to change, as well.

Now, diagnostic services are not only more readily available, but they can be performed more reliably and accurately (**FIG. 3**). The vast amount of process and machine monitoring data in the historian can now be analyzed by statistical analysis to further refine symptom detection earlier and provide more reliable prognosis to service with greater lead-time. CMS suppliers are now also offering automatic diagnostic services through a cloud-based webserver, so no client diagnostic server hardware or software is required. This cloud can then be connected to the historian as a seamless interface.

More and more historian-based condition monitoring applications are being developed, such as specific monitoring techniques like thermodynamic performance monitoring of turbomachinery, or for specific machines, such as reciprocating compressors.

Another important area of improvement with historian-based condition monitoring solution integration is the expanded user base. More specialists can contribute to the machine healthcare knowledge base, and more stakeholders who make important asset reliability decisions can have access to this information.

Takeaway. The IIoT has been the main driver for successfully breaking down proprietary interfaces in the information world for a large part of the industry, and the machine condition monitoring domain is no exception. As a result, historian-base condition monitoring has become much more intuitive, reliable, transparent and widespread. A lot of work remains to optimize the historian-based condition monitoring solution, but this is expected to be refined over time. HP

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Improve reliability and reduce maintenance with advanced analytics

A common misconception in large-scale process manufacturing is that minimizing downtime by increasing reliability is the key to increasing profitability. This mindset fails to address the fact that some downtime can improve capacity, increase production and minimize maintenance expenses. The most effective way to maximize production is by striking a balance between reducing costly unplanned downtime and taking proactive, calculated downtimes to restore or increase throughput capacity. Planned downtime also provides an opportunity for proactive maintenance, which is much less costly than reacting to failures after they occur.

Unplanned downtime is primarily due to equipment failure, and reducing it requires understanding the leading causes. It involves identifying historical losses, analyzing root causes and categorizing them in a way that can be easily summarized and consumed by relevant stakeholders.

This production-loss accounting activity is a taxing drain on valuable process engineering resources, consuming hours to days of their time for each reporting period. Reducing the time to insight for this analysis frees up engineering resources to make effective use of the data to reduce unplanned downtime and corresponding reactive maintenance through the design and implementation of process improvements.

Calculated, opportunistic downtime is a paradigm shift from the mentality of keeping a process unit running at all costs. These types of calculations require an optimization problem to be solved for identifying the minimum time to order fulfillment. Traditional solutions to this problem typically rely excessively on assumptions and are highly complex. A simpler, more transparent solution is required to achieve buy-in of this new operating strategy at all organizational levels.

Frontline subject matter experts (SMEs) can address both problems with advanced analytics solutions.

Traditional approaches encounter insurmountable limitations. As the field of data analytics advances, users are identifying and solving more computationally complex problems, revealing a

YTD losses by reason code – by month

Production loss reason code	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019
External factor, klb	862.78 klb	268.5 klb	413.09 klb	3698.6 klb	224.63 klb	532.95 klb
Feed constrained, klb	264.6 klb	533.9 klb	233.77 klb	1329.6 klb	0 klb	789.74 klb
Heating constrained, klb	2110.6 klb	3213.8 klb	1924.3 klb	403.02 klb	0 klb	1576.6 klb
High reactor DP, klb	507.72 klb	3152.1 klb	1471.8 klb	1088.7 klb	528.39 klb	191.47 klb
Human error, klb	0 klb	551.54 klb	0 klb	0 klb	275.54 klb	441.22 klb
Instrument reliability, klb	1142.6 klb	1465.3 klb	1157 klb	165.51 klb	578.21 klb	304.18 klb
Packaging constrained, klb	663.42 klb	0 klb	271.79 klb	400.47 klb	364.1 klb	0 klb
Refrigeration constrained, klb	0 klb	0 klb	84.214 klb	452.44 klb	3462.7 klb	5341.8 klb
Rotating equipment reliability, klb	779.37 klb	133.89 klb	976.7 klb	1947.2 klb	798.47 klb	333.53 klb

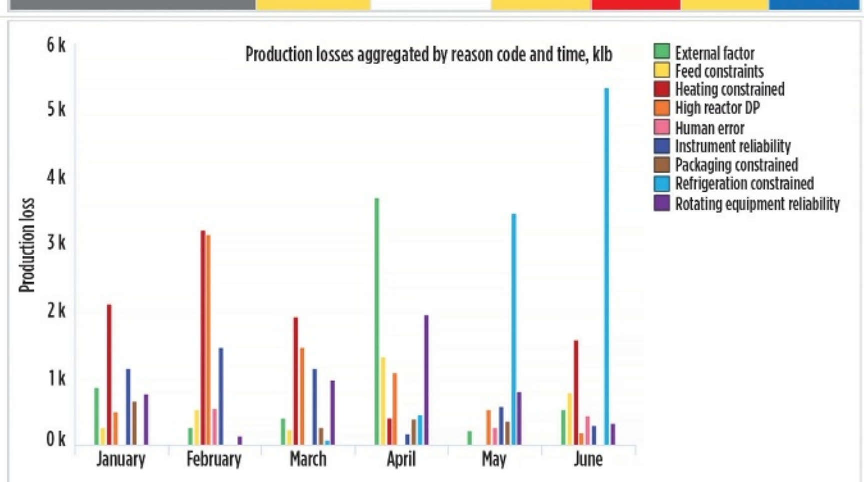

FIG. 1. Diagram from a production loss analysis dashboard for a petrochemical production unit.

host of insufficiencies in their traditional spreadsheet-based calculation tools. Leading limitations include data connectivity and access, computational performance, collaboration, versioning, visualization and reporting functionalities.

When establishing the root cause of a shutdown or a slowdown, it can be helpful to overlay process data with contextual information, such as operator logbook notes or maintenance work orders. Establishing a live connection to these types of data sources is challenging because, without it, engineers must extract data from multiple databases and build separate queries for each.

Spreadsheets encounter performance limitations when dealing with highly complex calculations or high data volumes. The latter of these becomes a serious problem when performing historical data aggregations, as the volume of data compounds with time. Spreadsheets reach row and column limits, and they become increasingly difficult to manipulate as file size increases.

Limited higher-order modeling functionalities require implementation of visual basics for application scripts or data dumps into other advanced programming tools. Both options present additional challenges regarding knowledge transfer and software tool maintenance.

Multi-user collaboration has become increasingly important as workforces adapt to a remote environment. Online tools allowing simultaneous input from multiple users are replacing offline versions. Spreadsheets and traditional desktop-based statistical modeling software present version management and other issues, creating a barrier to collaboration.

For presentation or sharing, spreadsheet-generated data visualizations are often embedded in slide decks or other reporting tools. These visualizations can be tedious to construct due to chart axes limits, as displaying more than two parameters together requires manual scaling, which is often specific to a single iteration of the visualization. All this effort ultimately results in reports full of static images that require reconstruction any time a report is created for a new time range.

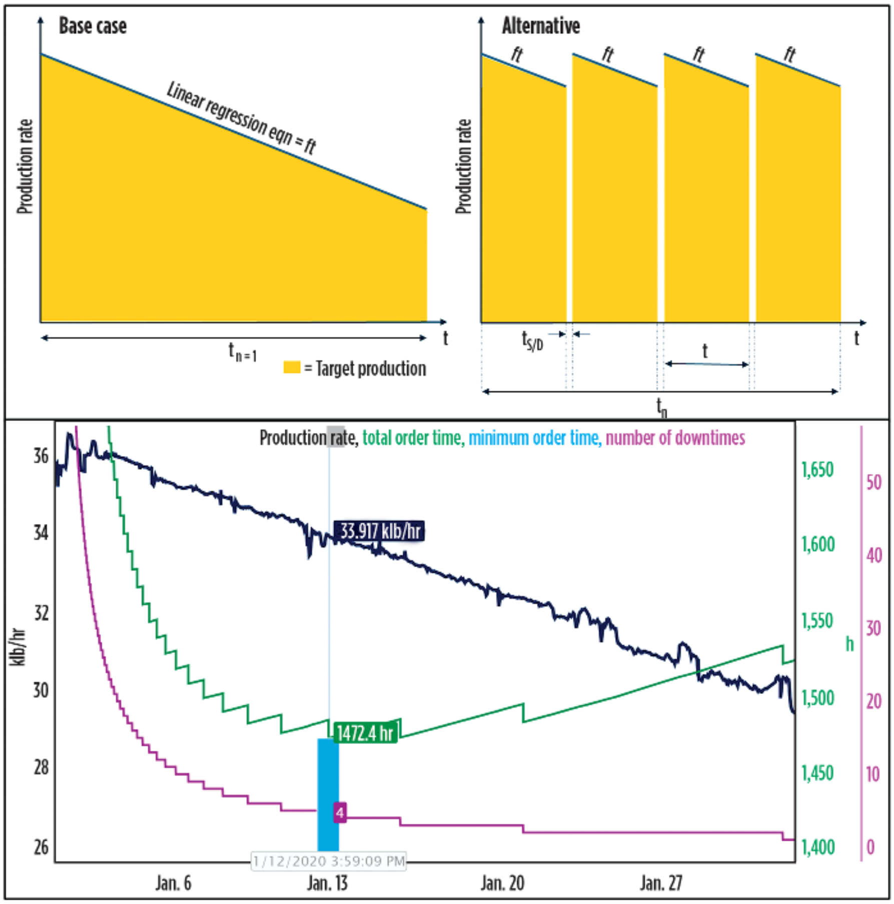

FIG. 2. Sketch depicting the optimization problem solved (top) and the graphical solution to the problem (bottom).

Advanced analytics solutions to overcome limitations. Browser-based advanced analytics software applications have filled the gaps left by spreadsheet-based calculations and reporting tools. Data connectivity and refreshing, along with computational load, interactive visuals, and live updating summary dashboards and reports are now well within reach.

Advanced analytics applications provide out-of-the box connectors to process data historians and SQL-based contextual databases—making process, maintenance, shift log and other data available to SMEs from a single application. Refreshed data is indexed on demand in a live updating environment, while maintaining the integrity of the data source.

Cloud or on-premises, server-based computing is leveraged, empowering SMEs to do calculations beyond the capabilities of their respective singular machines. This application saves information after every click, thus alleviating the threat of catastrophic crashes of large spreadsheets hours after the most recent save (an all-too-common occurrence when dealing with large volumes of data and complex calculations).

The combination of a versatile visualization pane and a robust calculation engine enables intermediate visual feedback and rapid iteration of analyses. Visualizing all the steps in a workflow enables users to identify potential issues sooner, troubleshoot more efficiently and minimize recycle time.

A "set it and forget it" dashboarding and reporting tool with a live connection to the data embedded in the visualizations saves engineers significant time that was previously spent updating and formatting reports. Auto updating or scheduled date range configuration ensures that high-horsepower calculations are run at optimal times, with reports made available for other users at a time of their choosing.

Use cases demonstrate data-driven operating strategies in practice. The author's company's digital technologies

have been deployed across various industries to enable customers to maximize long-term production, optimize maintenance spend and improve reliability—as shown in the following examples:

1. **Identification, categorization, summary and reporting of production losses**
   Challenge: Process manufacturers need to track and categorize performance losses to identify bad actors, justify improvement projects, and perform historical and global benchmarking. Production loss accounting for process manufacturing is a tedious activity that can cost days of work for process engineers. It requires identifying losses, performing root cause investigations, and documenting the events leading up to the loss. To make this information available to all interested personnel, it needs to be easily aggregated into reports that convey overall equipment effectiveness and identify unreliable equipment. Effective use of this data can inform decision making on capital project spending to remove process bottlenecks and upgrade unreliable equipment, with the end goal of minimizing downtime, maximizing production rates and optimizing maintenance. This categorization is hard to do retroactively, and most accurate performance loss coding is done either programmatically or by frontline personnel at the time of, or shortly after, a performance loss event.
   Solution: Digital tools[a] are used to identify performance losses by comparing an operation to ideal situations and creating conditions when the operation is constrained compared to target. Losses are categorized using specific conditions, where events can be placed in the correct categorical buckets, either manually or logically, based on configured thresholds. Summary visualizations are created in the application to represent the losses both graphically and tabularly. These summary visualizations are compiled into an organizer[b], where configurable live or scheduled date ranges are used to create automatically generated periodic reports, complete with collaboration and sharing capabilities (**FIG. 1**).
   Result: Automatically generated monthly reports can save 1 d/mos–5 d/mos of valuable process engineering time. This is time that engineers can get back to work on improvement projects and other value-added activities. Easily exportable historical loss data enables engineers to spend more time adding value to improvement projects and less time developing cost justifications.
2. **Production run length optimization**
   Challenge: Many process manufacturing units hit process throughput constraints over the course of a run, resulting in the degradation of production rates over time. These constraints are often reversible, but at the cost of shutting down to clean/maintain equipment. Sometimes, the decision to shut down and clean equipment—regaining the throughput rate upon startup—enables a unit to meet its production goals sooner. This type of planned downtime also reduces maintenance spend, as opposed to spending time reacting to equipment failure. Meeting targets sooner translates into more production and increased profits over the long term. Developing solutions to these types of optimization problems typically requires complex calculus, along with advanced modeling packages and programming experience.
   Solution: A calculation engine[c] was used to calculate the number of shutdowns that would minimize the total time required to produce a given order size. After determining the optimal number of shutdown/run cycles, engineers were able to determine the run length between shutdowns and to create a golden profile of these run cycles. The forecasted profile was then used to compare against the actual production rate to understand where the projected end-of-run date stood compared to the best-case order fulfillment date (**FIG. 2**).
   Result: A sold-out production unit had been looking at ways to increase capacity to meet demand. By implementing this proactive downtime strategy, they were able to meet supply chain targets on average 11% sooner over the course of the year. This allowed them to creep production volumes for multiple products by a proportional amount, thus growing sales and market share.

Takeaway. Reporting, complex calculations, modeling and other tasks required for analysis of time series process data have traditionally been performed using spreadsheets. As data volumes grow, along with pressures to increase personnel productivity, new solutions are needed to deal with these and other issues.

Advanced analytics applications that are specifically designed to deal with time-series process data provide a solution for large data volumes. As these use cases demonstrate, utilizing the right tool for the job saves hours or days of process engineer time, freeing these valuable individuals to work on higher-value activities that will optimize production, increase reliability and optimize maintenance.

NOTES

[a] Seeq Workbench
[b] Seeq Organizer Topic
[c] Seeq Formula

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Unlock margin by interconnecting refinery optimization silos with closed-loop AI

Refineries and chemical processing plants are complicated to model, control and optimize. Feedstock and intermediate hydrocarbon products, without complete compositional information, undergo various types of fractionation and reactions with added chemicals and catalysts.

Theoretically, the entire process could be represented by a universal rigorous first principle model that accounts for every valve, temperature, pressure, flow and level indicator in the plant. In theory, such a model could enable optimal manipulation of all valves in every unit throughout the plant, perfectly accounting for all disturbances, constraints and economic objectives.

However, theory and reality are two different things. Rigorous first principle models have existed for decades and have been useful in designing new catalysts and processes, as well as in offline process troubleshooting and analysis. Despite this, they have not been practical for the prediction, control and optimization of actual live plants. The reality of a process plant is far too complex to be accurately represented in real time by existing first principle models. Furthermore, reliable and complete measurements of ever-changing feedstock composition, required by first principle models, simply do not exist in actual plants. As a result, it has not been possible to use a universal first principle model to control and optimize a process plant.

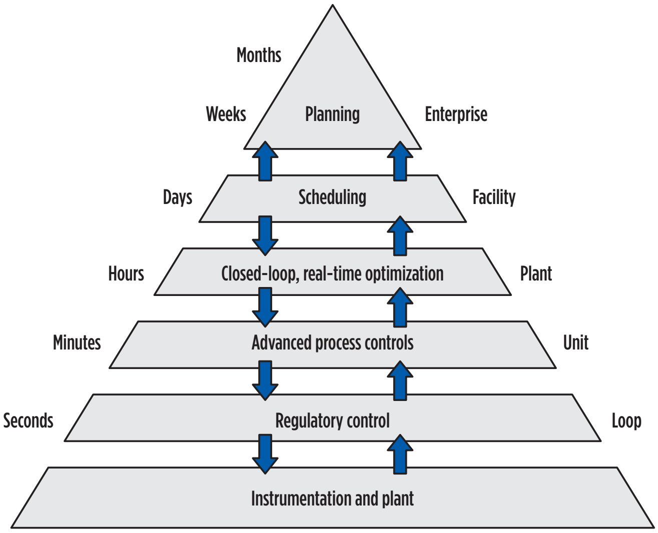

FIG. 1. Traditional process control and optimization stacked layers.

The traditional stack of process control and optimization. For the refining and chemical processing industry to function over the past 50 yr, simplifications had to be made to facilitate control and optimization of plants. A hierarchical stack of layers was formed, where each layer is simple enough to be well understood and manually engineered (**FIG. 1**). The model in each layer is either linear or composed of a set of first principle equations that can be linearized around a steady state. The plant is controlled in a cascaded manner, each layer controlling the layer below it. Each of these layers represents its own engineering discipline, methodologies and modeling techniques, and has its own separate team. The entire industry has become aligned around these layers.

A regulatory control layer implements thousands of the plant's proportional integral and derivative (PID) loops, each manipulating a valve or other final control element, while controlling an indicator. The advanced process control (APC) layer implements soft sensors and dozens of unit-level multivariable controllers. Several closed-loop/real-time optimization (RTO) models govern and coordinate multiple APC applications—driving them to targets generated by the planning and scheduling layers—through plant-wide linear programming (LP) models.

A dozen key levers—tens of millions of dollars in incremental annual margin. While this hierarchical control and optimization stack stabilizes plant operation, it misses an opportunity for several millions of dollars of annual margin per major refining process unit or chemical plant. Generally, the stack manipulates all plant process parameters suboptimally. For most of these thousands of parameters, the suboptimal operation has no economic detrimental effect. For a critical dozen or so of these process parameters, optimal manipulation on a 24/7 basis happens to hold the key to this margin opportunity. Since most refiners and chemical operators are not aware of its existence, this lost margin opportunity is not even being tracked by leadership teams.

Under the current hierarchical stack, every process variable is manipulated at a period of seconds to minutes by local PID loops and APC controllers, which consider temperatures, pressures, flows and levels at the variable's vicinity. The models at the higher layers of the stack, which govern a larger portion of the plant, do not operate at a detailed enough resolution to accurately guide the key variable's optimal manipulation. These simplified high-level models are not designed to relate

the minutes-to-hours effect of a change in the key variable on economically critical temperatures, pressures, flows and levels at other parts of the plant. Even if these simplified models were perfect, the required feedstock information for the calculation of the optimal variable value simply does not exist. The simplified high-level models can only provide rough, suboptimal, steady-state guidance to help drive the key variables.

An unfortunate effect of the vast resolution difference between the lower layers and upper layers of the stack is siloed teams. Process control teams are centered around the PID and APC models. Planners and economists are concentrated on the full-plant LP model or scheduling model. Each modeling layer requires wildly different skills, experience, terminology and technologies. As a result, these teams often have their own goals and initiatives and are not well positioned to collaborate in optimizing the plant.

The traditional hierarchical stack can solve simple multi-unit coordination and optimization problems, such as product blending. These are special cases where the relationship between key process parameters and the resulting economic properties is linear or easily linearized. It is only the large number of settings to be manipulated simultaneously that makes product blending an optimization opportunity. For such cases, a simplified subset of the plant LP model can run on a minute-wise or hour-wise frequency to coordinate the units and capture most of the value.

When it comes to more complicated (and more profitable) parts of the plant, the hierarchical approach cannot capture the full optimization opportunity. Conversion units are an example. First principle process models or simplified LP models can generate a rough recommendation for reactor temperature, accounting for feedstock and product economics. However, conversion unit reactors exhibit substantial nonlinear dynamics and are sensitive to the slightest changes in feed composition. Even 3°F–5°F away from the optimal reactor temperature implies over-cracking or under-cracking the feed and is detrimental to product yields. In these cases, the first principle model does not operate with enough resolution to manipulate the reactor temperature on a minute-by-minute basis, with respect to disturbances and ever-changing feed composition. Since feed composition is not reliably measured in real time, it is literally impossible to solve this problem via the traditional stack.

An interconnecting closed-loop model. Capturing the lost margin opportunity of closed-loop optimal manipulation of the plant's key levers requires refiners and chemical operators to break the mold. It requires them to look beyond the traditional hierarchical stack and to build a closed-loop interconnection between planning and economics, process engineering, process control and operations.

This new interconnecting model is not meant to replace the traditional stack. In fact, for most of the control loops, the replacement of linear technologies by a new approach will not provide a meaningful return on investment. The new interconnection model must be tightly built around the set of 10–15 most economically critical process parameters.

As opposed to augmenting a single-layer first principle optimization, the interconnecting model must be able to truly manipulate the critical process parameters in closed loop. The model must also have the internal complexity required to capture subtle to severe nonlinear dynamics between its inputs and outputs.

Critically, the new model must compensate for missing feedstock composition data, even when that composition varies subtly on a daily and hourly basis. The interconnecting model must deduce this compositional information from other measurable real-time sources of information, such as product yields and unit conditions.

This new closed-loop interconnecting model must not be limited to single layers of the traditional stack. A single model should be able to simultaneously operate at various layers, in different units and areas of the plant, and to interface different teams and engineering disciplines. It must understand the global nature of the optimization problem at hand, without losing the detailed resolution for local process subtleties.

To capture the lost margin, refiners and chemical operators are looking to artificial intelligence (AI) and machine learning (ML) to implement this new approach. Unfortunately, simply adding AI and ML capabilities into the stack will not provide the desired step change and will not capture the lost margin.

Integrating AI into the traditional layered stack of process control and optimization. Introducing AI and ML capabilities into the current stack may improve engineering productivity within each layer. Process control teams might be able to tune PID controllers faster and maintain APC models more efficiently with less invasive step testing. Planning and economics engineers may get better tools to consolidate multiple large spreadsheets. These are the types of advancements one might expect from augmenting the current layers with AI and ML.

A nascent industry discussion is the combination of first principle models with AI and ML for closed-loop optimization. However, the use of statistics in this respect is not new. For the several decades in which first principle models have been in use, plant data has always been employed to reconcile and fit the models to the current state of the plant. In fact, the recent scientific breakthroughs and developments that are driving AI and ML into public awareness are the result of going beyond first principle models. Recent AI discoveries are focused around enabling algorithms to build their own process representations and models.

For example, one may consider using a combination of ML and nonlinear dynamic first principle models for closed-loop optimization of complicated conversion units. In this case, thousands of parameters must be calibrated in real time by using some form of ML. There may not be enough process data to automatically fit the large number of model parameters in real time. If the first principle model is simplified enough to allow automated ML-based fitting, it will not capture the subtle nonlinearities that the critical valuable opportunities require. Furthermore, first principle models require feed composition data, which is not measured adequately and is, therefore, not available as a reliable or accurate input.

Decades-old statistical model-fitting methods are now being rebranded as ML or AI. While some of these methods might locally improve engineering productivity, they do not provide step-change improvements in plant profitability.

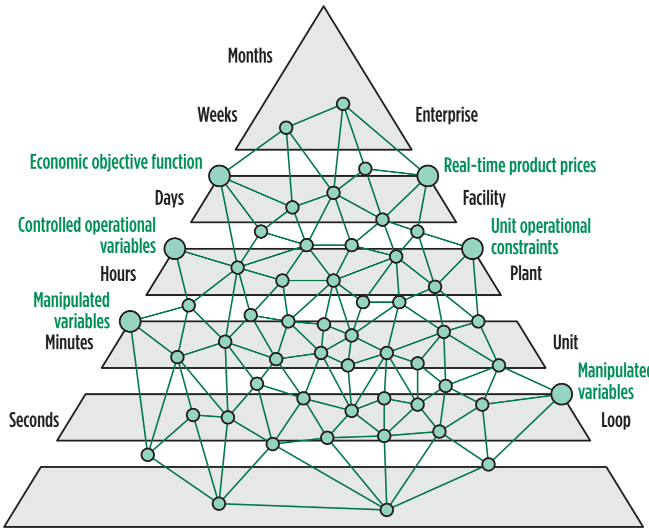

FIG. 2. Closed-loop interconnecting DNN.

A closed-loop DNN for interconnecting process optimization. There exists only one type of AI model capable of capturing these tens of millions of dollars of lost annual margin per plant: a closed-loop deep neural network (DNN) (**FIG. 2**). The DNN receives controlled operational and economic variables, real-time product prices and operational constraints, and then directly manipulates the critical variables. This DNN is a closed-loop interconnection between planning and economics, process engineering, process control and operations.

Over the past decade, DNNs have shattered through state-of-the-art benchmarks in areas such as imaging, text and speech. Recently, Google's DeepMind has used DNNs to solve the 50-yr fundamental computational biology mystery of protein folding prediction—a medicine breakthrough for mankind, potentially enabling drugs for diseases that include Alzheimer's, Parkinson's, diabetes, cancer and more. Applying DNNs in closed-loop control—a field called deep reinforcement learning (DRL)—exceeded researchers' expectations in 2016 by defeating the world champion in the board game known as "Go." Self-driving car control, one of the most challenging and complicated control problems, is also being solved by DRL.

The closed-loop process optimization DNN manipulates a small number of key process parameters at the APC and PID layers. It controls critical process constraints and optimizes to economic objectives. This translates to millions of dollars per major refining process unit or chemical plant.

The DNN uses historical process data to learn subtle nonlinear dynamics between selected variables. In many cases, several process vessels reside between the DNN input and output variables. Each relationship between these key variables is not consistent or self-contained. These relationships are each affected by dozens of other plant variables that the DNN must account for.

The DNN can compensate for the lack of real-time information about feed composition by using pressure, temperature, flow and level indications throughout process units. Slight disturbances in the (unmeasured) feed composition create subtle patterns across these process variables. These patterns are picked up and learned by the DNN. They are then used in real time to determine how key handles should be manipulated to optimize economic objectives while accounting for feed composition changes.

Aligning and interconnecting stakeholders through AI. The closed-loop DNN crosses process unit and plant area boundaries. It flows through the traditional layers and interconnects all the various teams. This allows everyone to speak the same language and to drive toward a common economic goal. The DNN does not necessarily need thousands of input and output variables. It manipulates carefully selected key variables by interconnecting real-time product prices with process constraints and economically critical properties.

Instead of each team managing its own model in a discrete stack layer, all the various disciplines interface with the closed-loop DNN. Planning and economics feed real-time product and feedstock prices directly into the neural network. Optionally, LP model outputs are also fed into the DNN. Process engineers input true unit operational constraints, along with known process relationships. Process control engineers manage the interactions between the DNN and the existing APC and DCS. Operators interact with the DNN on a 24/7 basis, constraining it to their desired bounds and limits in real time to allow for a safe and compliant closed-loop operation.

Takeaway. A stack of simplified layers has formed over decades to tackle the considerable complexity of refinery and chemical plant control and optimization. This traditional stack makes thousands of ongoing decisions to run the plant in a safe and stable manner. However, tens of millions of dollars in annual margins are being unrealized due to suboptimally operating the 10–15 most economically critical handles. To capture these lost opportunities, a new closed-loop process optimization model must work across the entire traditional stack, interconnect different layers and different teams, capture nonlinear relationships, and compensate for missing compositional information. Only a closed-loop DNN that bridges silos and links disciplines (such as planning and economics, process engineering, process control and operations) can accomplish this mission. This closed-loop DNN not only has the input/output simplicity to focus on critical key variables, but also the internal complexity to capture severe nonlinear dynamics and to use subtle data patterns to compensate for missing composition measurements. This interconnecting closed-loop process optimization DNN is how AI is truly leveraged to capture the incremental margin opportunity of optimal continuous operation of key plant handles. HP

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Smart manufacturing standardization: Driving global interoperability for enabling factories of the future

Smart manufacturing is a topic that has generated considerable discussions within industry and standards organizations. Starting off as a slick marketing term, the full impact of a manufacturing ecosystem that is enabled by information at each point in the product and production life cycle is compelling and encompassing. Smart manufacturing is a concept used to describe the application of different combinations of modern technologies to create a hyper-flexible, self-adapting manufacturing capability. It is an opportunity to create new forms of efficiency and flexibility by connecting different processes, information streams and stakeholders in a streamlined fashion.

The U.S. National Institute of Standards and Technology (NIST) defines smart manufacturing as "fully integrated, collaborative manufacturing systems that respond in real time to meet changing demands and conditions in the factory, in the supply network, and in customer needs." The Smart Manufacturing Leadership Coalition defines smart manufacturing as "the ability to solve existing and future problems via an open infrastructure that allows solutions to be implemented at the speed of business while creating advantaged value." The IEC and ISO jointly defined smart manufacturing as "manufacturing that improves its performance aspects with integrated and intelligent use of processes and resources in cyber, physical and human spheres to create and deliver products and services, which also collaborates with other domains within an enterprise's value chains."

In simple terms, smart manufacturing entails orchestrating physical and digital processes within factories and across other supply chain functions to optimize current and future supply and demand requirements. This is accomplished by transforming and improving ways in which people, processes and technologies operate to deliver the critical information needed to impact decision quality, efficiency, cost and agility. In turn, smart manufacturing is a corner-stone of digital supply chains and of Industry 4.0 strategies and programs.

The industrial policy initiatives of many nations (**FIG. 1**) are aggressively focused on the manufacturing sector. Digitization of manufacturing is important, and concentrated efforts are being made to develop and promote robust and localized manufacturing capabilities. Several nations anticipate that long-term benefits will be recognized beyond the manufacturing industry and diffused into other economic sectors. In turn, manufacturers are making significant changes to their strategies, advantageously leveraging these initiatives and improving local market competitiveness. The heritage of the various initiatives in **FIG. 1** might appear different, but their initial designs and core concepts have minimal differences. Several ideas and concepts are often borrowed from one another to be unique, and differentiation is created through the following:

- Promoting innovative models and setups through advanced technologies; these objectives are anchored by increasing integration, digitalization and new techniques for automating production
- Sponsoring incubation and co-development by combining industry, technology and service providers and original equipment manufacturers (OEMs) with academic and government organizations
- Developing and co-innovating new industry standards by way of exchange of experiences and access to testbeds and reference platforms.

Standards landscape. Standards are fundamental for enabling smart manufacturing. Different standards contribute in different ways to enabling the capabilities of smart manufacturing systems. **FIG. 2** illustrates three dimensions of smart manufacturing, along with relevant standards. Each dimension—product (green), production system (blue) and business (orange)—is shown within its own lifecycle.

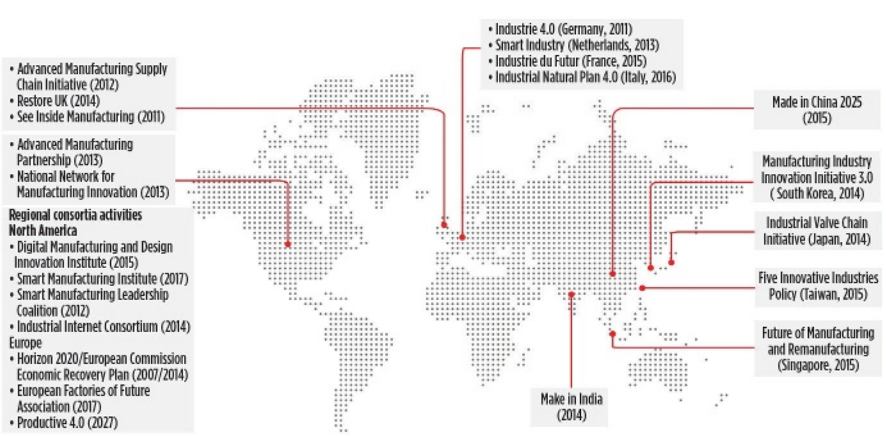

FIG. 1. Global smart manufacturing initiatives.

The product lifecycle is concerned with the information flows and controls, beginning at the early product design stage and continuing through to the product's end of life. The existing standards—particularly, in the areas of computer-aided design (CAD) and computer-aided manufacturing (CAM)—have greatly improved engineering efficiency. In addition, these standards enhance modeling accuracy and reduce product innovation cycles, thus contributing directly to manufacturing system agility and product quality.

The production system lifecycle focuses on the design, deployment, operation and decommissioning of an entire production facility, including its systems. Areas of standards that support production lifecycle activities include production system modeling data and practices; production system engineering, operations and maintenance; and production lifecycle management.

The business cycle addresses the functions of supplier and customer interactions. Standards for interactions among manufacturers, suppliers, customers, partners and even competitors include general business modeling standards and manufacturing-specific modeling standards and corresponding message protocols. These standards are the key to enhancing supply chain efficiency and manufacturing agility.

Each of these dimensions comes into play in the vertical integration of machines, plants and enterprise systems called "the manufacturing pyramid" (the central pentagon in **FIG. 2**). In smart manufacturing, autonomous and intelligent machine behaviors—including self-awareness, reasoning and planning, and self-correction—are key, but information resulting from these behaviors must flow up and down the pyramid. This integration from machine to plant to enterprise systems is vital, and it critically depends upon standards.

Standards-enabled smart manufacturing integration allows the following:

1. Access to field and plant data for making quick decisions and for optimizing production throughput and quality
2. Accurate measures of energy and material use
3. Improved shop floor safety and enhanced manufacturing sustainability.

Generally, existing manufacturing standards provide how-to instructions for designers, engineers, operators and decision makers to conduct disciplined activities within their domains. They also facilitate communication between stakeholders across domain borders, borders of the manufacturing system hierarchy and between lifecycle phases. Standards and reference models can offer an organization through a baseline for common lexicon for consistent engagement across different functions and geographies. At the most basic level, reference models and standards will help with business cases, technical feasibilities and value proposition evaluations. At a more detailed level, some might lend process maps and templates that help identify assets, applications and data, as well as potential resource allocations and security requirements—all of which are helpful for scale should prototypes be proven. However, standards still point toward individual processes and use cases vs. a complete smart manufacturing concept.

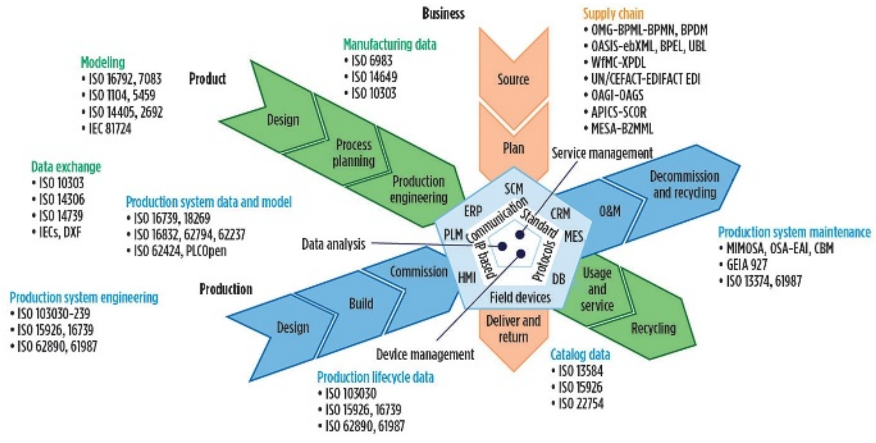

FIG. 2. Smart manufacturing standards (adapted from NIST IR 8107).

Driving global standards. Manufacturing organizations seek a manufacturing architecture that will remain consistent with a broader enterprise architecture for global visibility, collaboration and control, while still being flexible enough to support individual site goals. This is a challenge, especially for those who have inherited multiple divisions and sites, as well as multiple manufacturing styles and models (i.e., in-house, virtual or contracted).

Global standardization of the end-to-end supply network is done through common process standards that are transparent and supported by clear key performance indicators (KPIs). These standards provide a foundation for organizational consistency, without prohibiting local flexibility, reliability and innovation. While local execution is enabled by localizing global process standards to market specific best practices that consider the varying asset structures, other considerations (such as cultures, regulatory compliance and other local factors) have historically created constraints. These best practices are continuously improved to meet business objectives that are continually being reshaped by market dynamics.

Global process standards drive consistency and reliability in manufacturing, but deciding how far to extend them into local manufacturing operations without compromising agility is hard. The balance is tipping to a point where site autonomy and control over manufacturing systems is giving way to manufacturing standards mandated by enterprise architects. At the heart of these debates is how far to take the standardization of processes, information, technology and solutions, while allowing for specific local plant or functional needs. **FIG. 3** provides a process and system map where organizations can define how far to extend global standards into local manufacturing operations, and how to follow local best practices without compromising reliability and performance. Enterprises can define the point (or "locus") where unified and global standards, along with best practices and systems, align to deliver value to the business.

Beyond this point, the lack of local flexibility, as well as the time and cost to establish standards, fails to deliver business benefits. For example, a precision parts producer that supplies piston pins to multiple automotive OEMs worldwide requires consistent quality. This producer

pushes standardization down to the production processes, differentiating itself through a three-stage manufacturing process (cold forging, heat treating and finishing process) that is standard in each facility. Beyond quality, this degree of process standardization lays a foundation for agility in this producer's manufacturing network. Because each factory produces the product the same way, regardless of different production equipment, the company can shift production from site to site to mitigate variable costs or similar risks.

The standardization conundrum is not confined to business processes only. Standardization is a challenge, let alone managing the heterogeneous manufacturing information technology (IT) system landscape. Heavily emphasizing IT integration-driven standards like ANSI/ISA-95 (IEC/ISO 62264) for plant-to-business integration is not getting the job done fast enough. Although these standards are valuable for defining a common vocabulary that IT and operational technology (OT) stakeholders can use when devising manufacturing system architecture, they do not reflect the dynamic nature of manufacturing today. These standards perpetuate the belief that a generally accepted and well-defined boundary exists between global standardization and local execution, but that is not actually the case. Individual factories that house manufacturing applications spanning different activities and tasks with various underlying data models are the norm for many global manufacturers—and this has intensified for those that have grown through mergers and acquisitions. In addition, the actual maturity and depth of system functionalities can vary from process to process and from site to site. Beyond packaged applications, the business and capital cases for standardization across the multiple forms of OT found in manufacturing (such as data historians, programmable logic controllers (PLCs) and other plant equipment and devices) are difficult to accomplish.

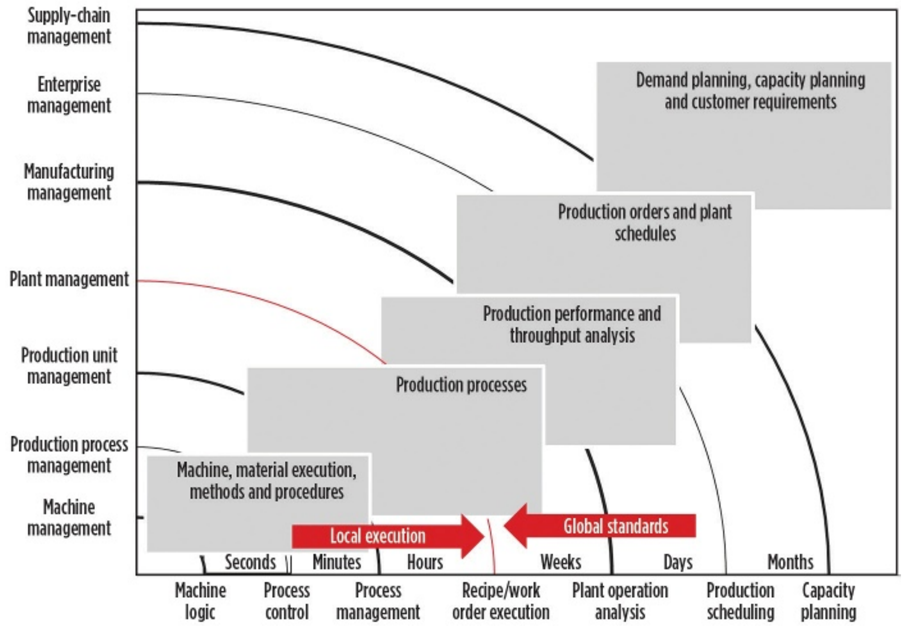

FIG. 3. Framework for manufacturing standardization.

Smart manufacturing centers of excellence (CoEs). Progressive organizations have created smart manufacturing CoEs to handle the coordination of scaling global process standards across their manufacturing networks. These CoEs are designed to enable operators to:

- Document existing practices across the manufacturing network
- Create a best-practice library
- Establish a baseline on which process improvement work is required
- Ensure consistent results.

These CoEs will develop the appropriate approaches or methodologies (e.g., total quality management) that will most effectively scale standards, so that multiple projects can happen simultaneously. Most manufacturing CoEs are virtual and are often dispersed within specific regions to best handle the coordination of local functions to achieve targeted milestones and outcomes. This approach is designed for:

- Using a library of commonly defined business process templates vs. relying on individual projects that are developing "in their own way"
- Establishing consistency across multiple projects, thereby enabling meaningful sharing of best practices for reducing complexity and redundancy
- Complying with governmental regulations.

Although they feature a top-down approach, CoEs also capture feedback from those responsible for executing best practices to identify process innovations that will improve manufacturing to drive better results from the bottom up. The result is a CoE that is a cornerstone for moving an organization from simply conducting individual lean or Six Sigma projects at sites to scaling larger programs with more impact that are part of the systematized and supply-chain-wide continuous improvement program.

Smart manufacturers realize that the standards that define them and the best practices that support them must evolve. If anything, the standards are just a baseline, and moving toward a way of working across multiple geographies and cultures requires more than control- and maturity-based process improvement. Cultural readiness is critical, and, in some organizations, the CoEs feature innovative ways to drive the acceptance of standards.

Takeaway. The need to link detailed—and diverse—manufacturing operations with supply chains requires product supply architecture that supports both global standardization and local execution. Smart manufacturers must develop a targeted strategy that can systemically balance repeatability, standardization and continuous improvement with the paradox of innovation, agility, digitalization and constant change. Companies may find success with "locus" of control—which is a level of abstraction and interface that lets the enterprise manage assets the same way, where all production units look the same, accept the same kinds of data and orders, and produce the same information results—even though their details may be very different. HP

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Successes and challenges installing the first proprietary closed-coke slurry system

The authors' company[a] licensed a two-drum delayed coking technology process unit to Grupa LOTOS in Gdansk, Poland. At the engineering design stage of the project, a closed-coke handling system was selected in lieu of a conventional open pit-pad system. The main reason for selecting the proprietary closed-coke slurry system[b] (CCSS) was to mitigate the issue of coke fines and volatile organic compounds (VOCs) emissions. The unit was successfully commissioned in 2019. The first implementation of this proprietary CCSS presented a few challenges that were overcome by carrying out some targeted engineering modifications. This article provides a comparison between the conventional coke handling system and the proprietary CCSS. This article also details the successful integration of the CCSS in the delayed coking unit (DCU).

Conventional coke handling system.

Either a pit or pad system can be designed for a DCU. Typically, both are considered a "combined pit and pad system." The combined coke pit and pad system consists of a pit and pad with a bridge crane for movement, storage and reclamation of green coke (**FIG. 1**). The coke pit and pad have retaining walls on all four sides, with one side being the coke drum structure. The system allows further dewatering of the green coke but requires additional plot space to include the pad next to the pit.

The coke pad is typically designed to store up to three days of coke production. The pit, located just below the coke drum structure, captures most of the coke cutting water and slopes the water towards the maze system. The maze system is designed to provide sufficient residence time to allow the coke fines to separate from the coke cutting water and settle to the bottom of the maze. An overflow weir—with sump pumps—is located at the end of the last maze compartment. The water that separates from the coke fines overflows the weir into the sump, where it is pumped to the hydrocyclone located in a neighboring structure near the maze area. The hydrocyclone further separates the coke fines from the water. The clarified water flows from the hydrocyclone to the clear water tank for re-use in the drilling operation. An overhead cab-operated bridge crane with clamshell bucket spans the entire coke pit and pad. The coke is spread out over the coke pad to dry out and dewater, usually taking up to 24 hr. In turn, the coke is reclaimed after dewatering and is transported by bridge crane to the inlet hopper, crusher, discharge hopper, belt feeder, belt conveying system and then either to a railcar or truck for shipment to the customer.

A different type of coke handling system involves the direct loading of the coke from the coke drum into railcars. However, this is not the recommended system due to many environmental and safety concerns, including hot material and water spillage during railcar loading, and a contamination trail of coke fines, water and dust during railcar movement throughout the plant.

The pit and pad system is a proven system that is widely used in the industry. Emissions from the pit and pad system can be controlled by the application of dust separation systems and good housekeeping.

The alternative to the conventional pit and pad system is the proprietary CCSS, which is further described in detail.

CCSS.

The CCSS handles the coke produced in a DCU as a zero-emissions, reliable and safe system. The elimination of emissions of fines to the atmosphere

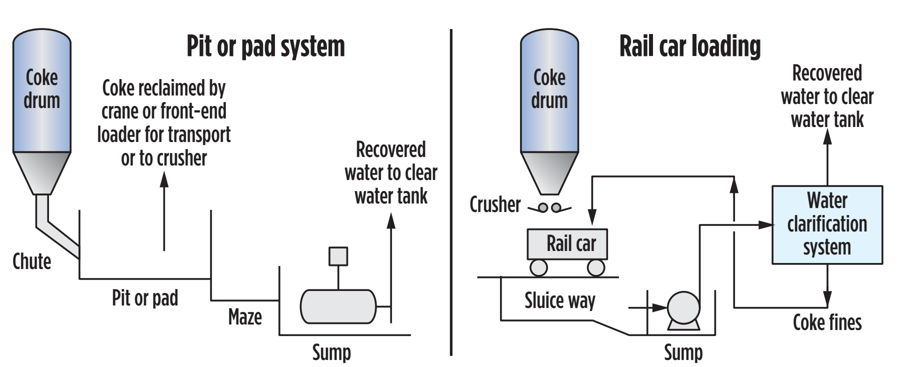

FIG. 1. Schematic flow scheme of an open pit-and-pad and railcar system.

is achieved by the enclosing of all operational steps in a "closed system." FIG. 2 shows a schematic of the CCSS.

In the closed system, the coke and water from the coke drum discharge to a special coke crusher via a transition piece. The transition piece is a permanent and sealed connection between the coke drum bottom unheading device and the coke crusher, capable of tolerating the thermal expansion of the coke drum. The inline coke crusher reduces the size of the coke particles suitable for processing, storing and selling the green coke product. FIG. 3 shows a picture of the transition piece and the coke crusher.

Downstream of the coke crusher, a slurry basin collects all incoming streams from the coke drum; water is added to the coke to form a pumpable slurry. A special slurry pump transports the water-coke mixture to closed dewatering bins, where

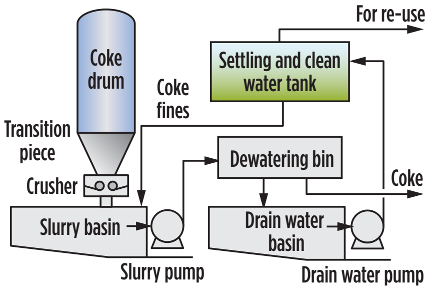

FIG. 2. Schematic of the CCSS[b].

coke and water are separated. Each bin is equipped with internal screens and can hold one batch of coke. The majority of fines produced from the cutting procedure are trapped instantly in this coke bed, resulting in clean water filtrate. The clean water filtrate is collected in the drain water basins and routed to the water settling and clean water tank for final cleaning and re-use for the coke cutting equipment, slurry transport and quenching.

After completion of dewatering, the coke is discharged from the dewatering bin via a vibration feeder, directly onto a belt conveyor, which transports the coke product to the coke storage area.

The integration of the closed system includes the intake of all streams, which are normally routed towards the pit/pad. Simultaneoulsy, the closed system provides clean water to the DCU for quenching and cutting.

The main advantages of the CCSS vs. conventional open systems are:

- The elimination of dust emissions to the atmosphere due to the closed design
- Low workforce requirements due to automation
- Reduced water consumption
- The reduction of equipment footprint
- More flexibility in equipment arrangement.

FIG. 3. View of the transition piece and crusher.

The design made for the Grupa LOTOS Gdansk refinery was a grassroots project and the first of its kind. All new CCSS structures may be installed in the pit/pad area, and integration and re-use of existing equipment can be investigated with a tailored customization. Several revamp studies, with concepts for maximum modularization and pre-fabrication, have already been executed and are of high interest to all units considering the elimination of fine emissions.

Startup challenges and troubleshooting.

The Grupa LOTOS DCU, featuring the proprietary CCSS, was commissioned in September 2019. Other than some challenges with the hydraulic decoking system, which had some impact, this first-ever commercial demonstration of the CCSS was an opportunity to detect any other unanticipated issues, which can now be addressed in subsequent designs and implementation. These issues—which mostly involved plugging in parts of the CCSS—and how they were handled are furthered detailed in the next section.

Hydraulic decoking system. During the initial period, the coke cutting pump tripped several times due to high bearing temperature, which caused delays in the decoking time. These delays impacted the coking/decoking schedule, and the unit could not be operated at the unit design throughput. The hydraulic decoking vendor was contacted, and upon the replacement of the shaft, impeller and drilling nozzle, the coke cutting pump tripping issue was resolved.

Plugging of the slurry pump and slurry line. During commissioning, plugging of the slurry pump and slurry line was observed. An additional flushing connection was provided on the suction side of the slurry pump, which helped avoid cavitation and improved stability of the flow pattern. In addition, the flow control logic of transport water was simplified, which contributed to a more stable operation.

Plugging and leaking of the transition piece. During initial operation, plugging was observed in the transition piece, which pushed some coke into the body of the bottom unheading device. The plugging forced a back-up of water and eventually caused a breakthrough, in which a large amount of water and coke would suddenly discharge from the coke drum. This caused the slurry basin to overflow

and carry coke particles into the neighboring drain water basin.

From the drain water basin, coke particles were pumped into the water settling tank, which resulted in the blocking of the desludging line. Moreover, some sludge even carried over into the clean water tank. Because of this, routine monitoring of the sludge levels in the water tanks was implemented. This step helped detect abnormal levels of sludge in the water tanks and allowed for corrective action. The desludging line was unblocked, and both water tanks were flushed. It was also recommended to install a coarse screen in the overflow between the basins to keep the coke particles inside the slurry basin. Future slurry basins will be designed to withstand a sudden discharge or breakthrough of the coke drum.

In addition, leakages were observed in the flanges of the transition piece. This issue was resolved by adding hydraulic clamps to the flexible connection of the transition piece, which are activated/tightened during the water quench and coke cutting steps.

Plugging of feed line. During operation, plugging was observed in the feed line. This was mitigated by modifying the decoking permissive to allow water through the feed line during cutting.

Instrumentation. In some events, the sudden filling of the slurry basin resulted in the radar-type level measurement sensor to be "dipped" in the liquid. The radar sensor can also be affected by the presence of steam. These events caused the measurement to freeze at its previous value for approximately 20 min each time and resulted in the level control being ineffective and taken to manual control. Instead of a radar sensor, a second differential pressure sensor can be implemented to alleviate this issue.

Dewatering/coke transport. During startup, the coke discharged to the transport system was still wet and partly unsuitable for inclined conveying.

The quality of coke has an effect on the cutting and dewatering times. Harder coke requires extended coke cutting, and powdery coke needs more time for dewatering. Both effects result in a longer dewatering cycle.

After gaining some experience with the dewatering rates, an improved operating procedure was established, and coke moisture reached an acceptable level.

Takeaway. The first implementation of the proprietary CCSS was successfully integrated with a licensed DCU. Successful execution in commissioning showcased a path to improved sustainability that refiners can follow as an alternative to a conventional open pit/pad coke handling process. The lessons learned during this project have helped improve CCSS engineering design practices. Future projects are expected to have more robust designs that present a much cleaner alternative to an open pit/pad coke handling system. All of the existing open pit/pad systems where refiners wish to minimize coke fine emissions may become candidates for revamp to the environmentally friendly CCSS. HP

NOTES

[a] Chevron Lummus Global
[b] TRIPLAN's Closed Coke Slurry System (CCSS)

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Optimizing for viability—VDU revamp in a brownfield project

Revamping an existing column in an operating plant for higher throughput is a challenge, especially when the column is already operating at its rated capacity. This is particularly true for a vacuum distillation unit (VDU) column, which involves multiple product and pumparound streams and associated auxiliary units, such as a steam ejector system.

Optimizing the design and operation of the column is inevitable to ensure the viability of a brownfield project, as it avoids major modifications to the column and its associated auxiliary systems. This article discusses how optimization was carried out on the design and operation of an existing VDU column in an oil refinery, avoiding major modifications of the associated ejector, steam, cooling water, sour water systems and heat exchanger network and allowing a brownfield project to remain commercially viable.

Case study background. A case study of an existing VDU column at a refinery in Malaysia is included in this article. The VDU column was designed to operate at 9 mmHg operating pressure with a throughput capacity of 3,500 bpd of low-sulfur waxy residue (LSWR) from an upstream crude distillation unit (CDU).

As part of the refinery's business growth strategy, the VDU column was considered for debottlenecking to allow additional throughput of LSWR, which is lighter than the existing throughput at 23,000 bpd to the unit. The lighter, higher LSWR throughput led to higher non-condensable and condensable vapor flows at the top of the column, thereby massively increasing the column internals loading and producing higher column operating pressure, which placed additional burden on the overhead steam ejector system.

Major modifications to the column shell diameters, steam ejectors and condensers were expected, and the replacement of the equipment would require massive structural modification within a congested, operating plant. On top of that, with the larger steam ejectors and condensers, major modifications to the associated steam generation system, cooling water system and sour water treating unit were expected.

The total cost of the required modifications was estimated at approximately $25 MM, which would render the project uneconomical. Replacing the VDU column itself was not an option in view of the sheer complexity of the construction work required in the operating plant, which would require extended downtime of the refinery. The economic loss associated with the prolonged downtime would outweigh the benefit of debottlenecking the column. A creative solution was needed to economically optimize the column operation.

Solution for brownfield optimization of the VDU. One way to make the project economically viable is to optimize the column operating conditions and column internals design efficiencies and to exhaust all available heat duties within the pumparound and heat integration network to reduce the impact to the existing ejector system and minimize the modifications to the VDU unit. This plan was outlined using industrially acceptable process simulators and an in-house sizing software for column internals.

Optimizing the column operating conditions includes increasing column bed efficiencies, adjusting the operating pressure, redistributing heat duties in the heat exchanger network, optimizing pumparound flow, and adjusting the column temperature profile and inlet temperature. These modifications led to changes for both the mass and heat transfer profiles within the column. These changes resulted in the reduction of column internals liquid and vapor traffic, thereby decreasing the total load at the top of the column to the overhead steam ejector system.

Debottlenecking a VDU column. Understanding how a VDU column works and the influence of the auxiliary systems to the VDU column operation are key to optimizing both the design and operation of the column itself. The VDU column under study was a typical design of five packed beds, one flashing section and one stripping section, operated under vacuum conditions at 9 mmHg. The VDU is designed to fractionate heavy LSWR into product streams including light vacuum gasoil (LVGO), medium VGO (MVGO), heavy VGO (HVGO) and vacuum residue (VR). **FIG. 1** shows the schematic of the VDU under study.

A two-phase feed enters the VDU column flashing section via an upstream fired heater. Lighter vapor components will rise up the column to the wash, bottom pumparound (BPA), middle pumparound (MPA), fractionation and top pumparound (TPA) sections to be further distilled to product streams through both the heat recovery pumparound beds and product purification

beds. The heavier liquid components will go down the column bottom through the stripping section to ensure that the lighter portion can still be recovered before coming out of the VDU column as the VR product stream.

The VDU debottlenecking project will introduce lighter LSWR at an increased capacity of 23,000 bpd into the VDU column. Due to the higher throughput and to allow for adequate separation within the column, a new fired heater was added upstream of the VDU column to provide an additional 20 MW of heat duty. To meet the debottlenecking objectives, the column not only receives additional mass throughput but also receives additional heat load to the column heat balance.

Through detailed tray-to-tray simulation and hydraulic sizing calculations performed at each of the column internals, it was observed that introducing additional mass throughput and heat load to the column caused the following:

1. Substantial vapor traffic rising up the column from the flashing section to the TPA section
2. Greater pumparound duty requirement for all pumparound sections due to higher vapor traffic inside the column (this is to balance out the additional heat introduced by the new fired heater)
3. Lighter components slipping down to the VR section due to higher vapor traffic in the column, thereby compromising the VR product initial boiling point (IBP) specification
4. Additional column pumpdown requirement at fractionation and wash oil sections due to an increase in liquid load
5. Higher pressure drop across the column due to higher holdups caused by greater liquid and vapor traffic.

These changes to the column operating conditions will translate into major modifications to the VDU column and its auxiliary systems if no optimization is performed on the column internals design and operation.

VDU column modification without optimization. The conventional way of debottlenecking a VDU column involves a total revamp of the column, which could include the total replacement of the column internals to higher-performance internals; an increase in the column inlet and outlet nozzles, thereby allowing a larger column diameter; or, at the extreme end, the total replacement of the column itself. To manage the additional heat load introduced into the VDU column heat balance, additional external cooling or heat sinks must be introduced, either through the introduction of additional heat exchangers in the heat exchanger network or the provision of new water or air coolers.

In addition to these items, higher vapor load (exiting from the top of the column and consisting of both condensable and noncondensable hydrocarbon components) could result in a massive, multistage ejector modification requirement. To support the ejector modification, major modifications to the associated steam generation system, cooling water system and sour water treating unit were expected.

VDU column modification with optimization. To prevent major modifications to the VDU column, the column design and operation were optimized before the modification scope was identified. The VDU column operating parameters and each section within the VDU column were examined in detail, and iterative simulations were performed to ensure that each bed within the VDU column could be fully optimized.

The following optimization approach was applied to minimize the scope of the VDU column modifications:

1. The fired heater coil outlet temperature (COT) into the VDU column was reduced from the design operating temperature to the lowest operating temperature at which the column is still able to allow good separation to occur within the column. This optimizes the heat balance within the VDU column and the capital investment required to handle the additional heat within the heat exchanger network.
2. The column top vacuum operating pressure was increased from the design operating pressure to the maximum operating pressure at which good separation can still occur in the column. This reduces the amount of condensable and noncondensable hydrocarbon components at the vapor outlet of the VDU column to the ejector system, avoiding major modifications to the ejector system and associated steam, cooling water and sour water treating units.
3. For all heat recovery pumparound beds within the VDU column (i.e., TPA, MPA and BPA), high-efficiency packing with additional surface area was selected. This type of packing does not sacrifice the void fraction (i.e., the capability to withstand higher load).
4. The heat recovery through the heat exchanger network was optimized to achieve maximum heat integration within the VDU unit and minimize capital investment for the modification of existing heat exchangers, except

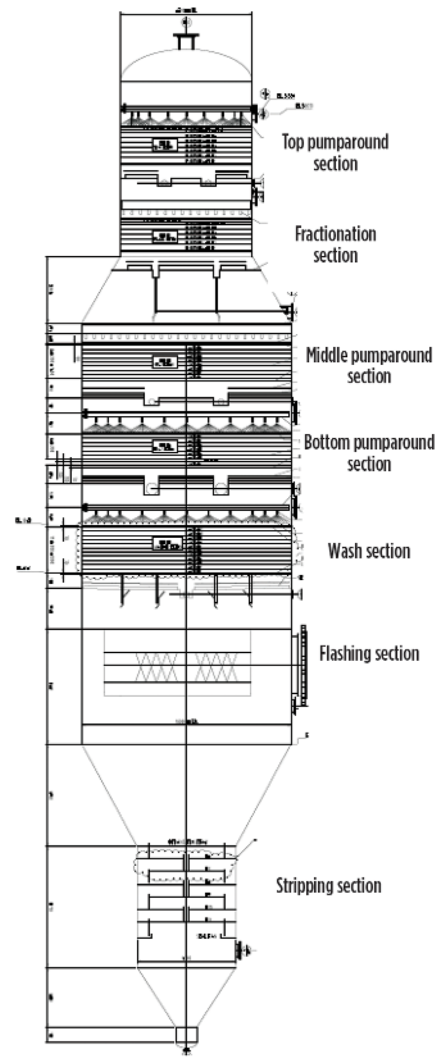

FIG. 1. Schematic of the case study VDU column.

TABLE 1. VDU revamp scope with and without optimization

	Revamp scope without optimization	Revamp scope with optimization
Base scope	VDU column shell and nozzle modification: • VDU column shell diameter increase (+15% diameter) • VDU column height increase (+10% height) • Increase TPA return nozzle size and change spray distributor (+25% increase in size)	VDU column shell and nozzle modification: • Increase TPA return nozzle size and change spray distributor (+25% increase in size)
	Packing beds and internals replacement: • Replacement of the TPA, MPA and BPA sections to high-capacity packed bed without reducing the efficiency	Packing beds and internals replacement: • Replacement of the TPA, MPA and BPA sections to a high-capacity packed bed without reducing the efficiency • Latest technology development of a hybrid packed bed was chosen
	Replacement of TPA air coolers (+25% duty)	Replacement of TPA air coolers (+25% duty)
	Replacement of LVGO pumps (+150% capacity)	Replacement of LVGO pumps (+40% capacity)
	Replacement of MPA/MVGO pumps (+93% capacity)	Replacement of MPA/MVGO pumps (+95% capacity)
	Replacement of extra-HVGO recycle pumps (+20% head rise)	Replacement of extra-HVGO recycle pumps (+20% head rise)
	Replacement of a VR pump (+35% capacity)	Replacement of a VR pump (+35% capacity and +30% head rise)
Additional scope	Replacement of first-stage ejector (largest ejector system): • Increase from 15-m length to 42-m length • Associated steel structure for new ejector system	Replacement of third-stage ejector (smallest ejector system): • Increase from 1-m length to 1.6-m length
	New cooling water package and associated interconnected piping (+1,670 t/hr capacity)	Replacement of VR/LSWR cooler (+7% duty)
	New steam generation package and associated interconnected piping (+59.5 t/hr capacity)	–
	New sour water treating unit (+59.5 t/hr capacity)	–

for additional water or air coolers for final heat rejection. This is achievable through the use of a higher-efficiency bed at both the TPA and MPA sections, allowing better heat recovery at lower pumparound flow, which reduces both the column internals vapor and liquid traffic and improves heat recovery in the highly integrated heat exchanger network.

5. For all fractionation packing beds within the VDU unit (i.e., the fractionation and wash sections), hybrid packed beds were chosen to provide better performance (i.e., a higher void fraction without sacrificing efficiency). By using the high-efficiency packed bed, the hydraulic limitation was reduced without having to increase the column diameter, while still meeting separation and product quality requirements. This choice avoids the need to modify the VDU column shell.

With the considered optimization approaches, it was observed that the VDU column total internals vapor and liquid traffic was greatly reduced throughout the column, while maintaining the products separation and quality. The optimization also resulted in lower vapor condensable and noncondensable flows at the top of the column. These approaches avoid major modifications to the VDU column, its auxiliary systems and the heat exchanger network, significantly reducing the capital investment of the brownfield project.

Results and discussion. The modifications required for the VDU column with and without the optimization are listed in **TABLE 1.**

The optimization of the VDU column operating conditions and internals design avoids the replacement of the first-stage ejector (the largest ejector system), the associated steel structure for the ejector, the requirement for a new cooling water package and associated interconnected piping, a new steam generation package and associated interconnected piping, a new sour water treating unit, additional heat exchangers, and cooling water or air coolers in the heat exchanger network. The total cost avoidance as a result of the optimization work is estimated at approximately $25 MM, which allows the project to stay economically viable.

Additionally, the project recently underwent a performance test run and was able to meet the desired performance guarantees.

Takeaway. In conclusion, optimization of column operating conditions and design is critical when the column is already operating at its rated capacity in a brownfield project. A case study of a VDU column in a Malaysian oil refinery indicates that massive modifications are required if optimization is not carried out on the column operating conditions, which add unnecessary capital expenditure and may render the project economically unviable. HP

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Specifying internals in sour water strippers—Part 1

A sour water stripper (SWS) system is a common process in petroleum refineries and other processes where hydrogen sulfide (H_2S) is present. While not a revenue generator, the sour water treating system is a critical unit operation and can be a significant bottleneck to facility production rates if it is not adequately sized or if it is forced to operate at partial loads due to maintenance issues. As a result, a balance must be struck between minimizing capital costs, while still providing a reliable and flexible sour water treating system.

Part 1 provides an overview of the auxiliary separation equipment needed to remove hydrocarbons and other contaminants from the sour water prior to the stripper and reviews the design of SWS columns containing trays. In Part 2, which will be published in the March issue of *Hydrocarbon Processing*, the internals for packed SWS columns will be discussed, along with a summary of potential issues that may be encountered in operation of the SWS system.

SWS systems. The SWS system receives sour water from different upstream unit operations, which in a petroleum refinery may include crude units, hydrocrackers, hydrotreaters, catalytic crackers, etc. The sour water streams from each of these unit operations will vary in composition but will generally have some fraction of ammonia (NH_3) and H_2S present in solution. This article considers SWSs that have NH_3 and H_2S as the primary species to be removed; it excludes consideration of other species, such as cyanides, phenol, etc. All recommendations given are in this context.

The SWS system collects the sour water streams from different unit operations, removes hydrocarbons, solids, etc., and removes the NH_3 and H_2S from the water by heating and stripping. The liberated NH_3 and H_2S, along with a large fraction of water, flow to downstream unit operations as a vapor for further treatment. The stripped water may be disposed of as wastewater, or if it meets specifications, it may be used in other process units in the refinery, such as the crude oil desalter. A typical, simple SWS process flow diagram is shown in **FIG. 1.**

Different variations of the process flow shown in **FIG. 1.** exist. Two frequently encountered differences are:

1. The addition of live steam into the column instead of a steam reboiler. Live steam will not foul or have maintenance issues that would be associated with the steam reboiler in an SWS, but all of the steam introduced into the stripper will need to be made up in the facility's steam system with fresh steam and additional stripped water will need to be disposed of.
2. A pumparound system in the top of the SWS instead of the conventional overhead condenser and reflux drum. In this design, a stream of water from the stripper is cooled and pumped to the top of the SWS to maintain the overheads temperature from the stripper at the same temperature it would be leaving the reflux drum in the conventional design. This design avoids the need for the stripper overhead condenser, which can be an expensive and maintenance-intensive piece of equipment. The downside to this option is that additional height is needed in the SWS for the cooling section, and the liquid pumparound equipment is made of upgraded metallurgy.

The SWS and associated equipment are not typically revenue generators in any facility; however, the unit operation is critical to the rest of the facility's opera-

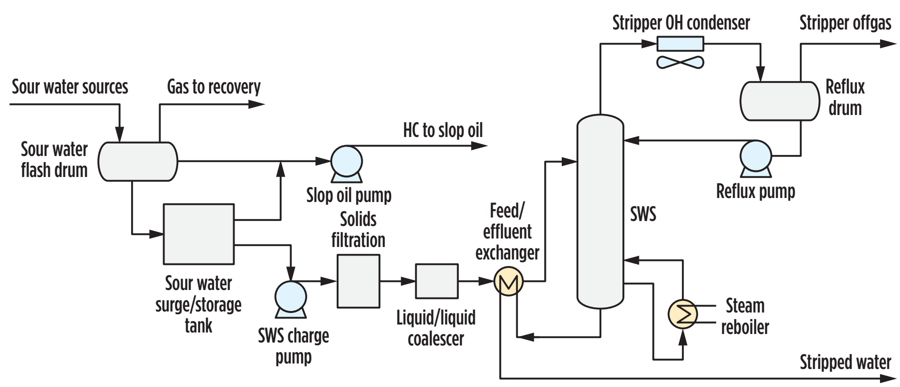

FIG. 1. Simplified process flow diagram for a SWS.

tion since most of the sour water in the facility has to be treated in the SWS before it can be reused or processed further. The sour water fed to the SWS will also change over time, with increasing or decreasing amounts of NH_3 and H_2S in the water and overall water flowrates varying daily. The designer of the SWS is challenged to design a flexible and robust system that can meet a variety of different feed conditions, while also minimizing the cost of the equipment. Above all, the SWS cannot be a bottleneck in the overall facility and must strip the sour water reliably in all operating conditions.

There is a long history of technical papers that thoroughly discuss many aspects of SWSs.[1–6] This article is not meant to be a comprehensive review of SWSs. This article reviews a few of the key design choices available for the SWS system, and then specifically focuses on some of the internals of the SWS tower. The choice of internals in the SWS can be difficult, with a range of different sources available in literature, and few very thorough technical analyses completed to guide the designer to the best solution.

The SWS system is a critical unit operation and can be a significant bottleneck to facility production rates if it is not adequately sized or forced to operate at partial loads due to maintenance issues.

Auxiliary sour water separation equipment. For the SWS tower—and the internals discussed later in this article—to function properly, they must not foul too quickly. Sour water stripping is generally considered a severe fouling service. The stripper functions much better if the chances for fouling and foaming are reduced by adequate pretreatment of the sour water. Therefore, this section examines the equipment upstream of the SWS that reduces fouling and foaming issues in the stripper tower.

Sour water flash drum. As shown in FIG. 1, sour water is collected in a flash drum where hydrocarbon vapors and liquids are removed. The vapors are flashed close to ambient conditions to remove as much hydrocarbon as possible. The flashed gas is typically sent to a low-pressure destination such as a flare gas recovery system, combustion device or fuel gas as allowed by environmental regulations. At some sites, the flash gas is routed to the SWS overhead gas line; however, this can result in a significant and variable quantity of hydrocarbons being fed to the downstream unit [e.g., a sulfur recovery unit (SRU) or other technology] that can adversely impact performance of that downstream unit.[7] Flash gas with no condensable hydrocarbons could possibly be routed to the quench tower in an amine tail gas treating unit.[7,8]

The sour water fed to the flash drum often also contains liquid hydrocarbon/oil that needs to be removed to protect the rest of the SWS system from fouling and prevent foaming in the stripping column. The flash drum is usually a three-phase, horizontal vessel. A baffle system installed at one end of the flash drum is often used to skim oil from the water before it is pumped to the sour water surge tank. The oil overflows the weir into a collection compartment in the sour water flash drum for removal. Another means of collecting oil is to install a draw-off box in the sour water flash drum that could collect the oil overflowing to it. The minimum recommended residence time for the sour water inside the flash drum is 20 min, with a liquid level of 50%–60% being optimal. The sour water flash drum should include connections for level bridles on the hydrocarbon and water side of the vessel. High- and low-level alarms and pressure indication are also used. Demisting equipment or other similar plugging-prone internals are typically not used in the sour water flash drum because they may rapidly plug or corrode. The hydrocarbons collected in the sour water flash drum are often pumped to a slop system for further processing.

Sour water surge/storage tank. The sour water from the flash drum is fed to a surge/storage tank. The tank is designed with several days of storage in case the SWS goes down. With long residence times, dissolved hydrocarbon liquid and emulsions can separate from the water and collect at the interface level in the tank. The temperature of the sour water in the tank is usually less than in the flash drum, which further reduces the solubility of hydrocarbons in the sour water. Some in the industry have also observed that NH_3 or amine-laden water increases the solubility of certain types of gasoline and higher boiling range aromatic hydrocarbons (similar to benzene) in the sour water, making it difficult to separate such that significant fouling was observed in the stripper.[6] The sour water surge tank may not remove all hydrocarbons that remain in the sour water after the surge drum, but the tank does help by removing at least some of them.

The surge tank also allows for mixing of the sour water from different time periods, so the composition is more uniform. If the sour water composition changes considerably or rapidly, the stripper may not function appropriately. By keeping the sour water flow and feed composition consistent, the stripper will be easier to control, and a more consistent treated water product can be achieved. Short-circuiting—where the sour water entering the tank inlet flows preferentially to the tank outlet without adequate mixing or residence time—is a common problem that results in higher variability in sour water composition and poor hydrocarbon separation. In the question-and-answer portion of a recent industry trade symposium[9], measures that were said to mitigate short circuiting included (1) having the entry and exit on opposite sides of the tank and (2) having the entry and exit at different heights.

The surge tank can be a fixed or floating-roof-type storage tank. Floating roofs can be either open or internal. However, due to the potential for odors, a fixed-roof tank is often used. FIG. 2 shows an example of a surge tank with a fixed roof and internal floating roof. The floating roof may have a double-seal design to minimize emissions.

Vacuum breakers and pressure relief valves should be installed on fixed-roof tanks that are not vented to the atmosphere. By letting air in, vacuum breakers can keep the tank from collapsing during pump-out or upon cooling; however, air ingress can lead to the formation of a dangerous combination of oxygen, hydrocarbons and H_2S in the tank headspace that could lead to an explosion. Nitrogen or inert gas blanketing is often used for this

reason. However, inert blanketing has its own problems. For example, using an inert blanket can lead to the formation of pyrophoric iron sulfides on exposed steel surfaces. If air is subsequently allowed into the headspace (e.g., due to a fault in the system or due to accident) and thus creates an explosive mixture, then the pyrophoric material can ignite that mixture and cause an explosion. Examples of explosions that have happened in SWS storage tanks are documented in literature.[10] Much care is advised in designing inert blanketing systems for sour water tanks.

The tank may need to have a minimum of three days retention time during normal operation at 50%–60% full, including another couple of days of capacity for sour water storage. Whether the tank has a fixed or floating roof, it is common to allow a hydrocarbon layer to float above the sour water as a "blanket" to limit vapors from escaping that may be odorous or toxic. This layer may be a diesel range material and is sometimes also referred to as a rag layer. Oil skims should be used to remove oil as the floating layer grows. Floating skim nozzles with a non-metallic flexible hose are sometimes used. The design should include an automatic tank level gauge system, with provisions for measuring the thickness of the hydrocarbon rag layer on the aqueous layer, as well. A literature source[11] reports that nuclear signals or sound waves can be used to measure the interface, but the authors' company is aware of successful measurement using capacitance probes, as well. In a floating-roof tank, the capacitance probe can be mounted on the floating tank roof. Level control is critical to minimize hydrocarbon carryover to the SWS; the location of the control devices is vital to accurately measure the interface.

The tank is typically made from carbon steel, and a suitable durable coating may be used on all interior surfaces to minimize corrosion of the tank surfaces.

Solids and heavy oils will sink to the bottom of the tank. For this reason, the tank bottom should be designed to slope (e.g., approximately 3 in. for every 100 in.) to a low point drain. The tank discharge to the pump is also generally elevated somewhat above the tank bottom to allow room for heavy materials to accumulate without exiting the tank with the sour water. The sour water is pumped using flow control to the stripper.

Angled ports are sometimes installed on the sour water tank so that it can be vigorously circulated (e.g., with a large portable pump) to stir up solids and then filter the solids out during turnarounds. This reduces the frequency with which persons will have to go inside the tank to clean it out. Images of the usually uninsulated exterior walls of the tank from a thermal camera can sometimes be used to evaluate solids levels. In addition, the surge tank should have a bypass line around it so that it can be bypassed (e.g., for inspection), if needed.

Sour water solids filtration/coalescing filters. Additional solids filtration and coalescing technology may be installed downstream of the sour water charge pump and upstream of the feed/effluent exchanger. Solid particle filters should be used upstream of a liquid/liquid coalescer. Suspended solids removal improves the efficiency of the coalescer by weakening the hydrocarbon emulsion and minimizes fouling from solids in the sour water heat exchangers, stripper reboiler (if used) and stripper trays or packing. Some refineries reportedly have used a strainer instead of a more expensive filter.

The liquid/liquid coalescer helps to control hydrocarbon fouling in the same sour water equipment. Disposable, microfiber-based coalescers are reported to give adequate separation of hydrocarbon emulsions.[11] During a recent industry symposium[9], use of liquid/liquid coalescers for partial treatment of the feed sour water was reported to increase the time between cleaning from once every 9 mos to twice that length in a refinery with three SWSs.

Hydrocarbons in the stripper overhead gas can also cause operational issues in the downstream SRU or other processing technology. Hydrocarbons in the stripper bottoms that are routed to a water treatment plant can pose environmental/regulatory concerns, as well. Therefore, using filters and liquid coalescers can benefit not only the SWS but also overall refinery operations.

SWS diameter and feed water feed locations. Many SWSs experience severe foaming, which needs to be accounted for when sizing the column. As such, the capacity should be de-rated to account for foaming, and a system factor of 0.6–0.7 is typically recommended. This can make the SWS much wider in diameter than would be anticipated for a column that, at least on first appearance, is basically boiling water.

The location of the sour water feed in the stripper can vary based on several factors, including whether trays or packing are used, number of trays used, the desire for lower steam usage, inlet H_2S and NH_3 concentration and treatment specification, as well as operating temperature and pressure. If a pumparound cooling system is used in lieu of an overhead condenser and reflux drum, the feed location will be below these trays, as well. Optimal feed location can be determined in a process simulation, and the feed location is usually located within the top several trays in trayed columns. In addition, if the column is constructed from carbon steel, it may be lined with a corrosion-resistant durable coating or made of corrosion-resistant

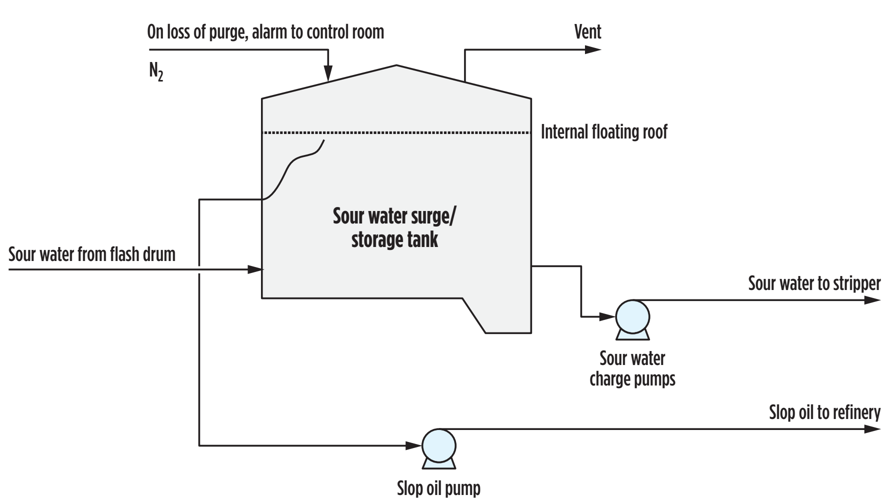

FIG. 2. Simplified schematic of a sour water surge tank (internal floating roof).

alloy above the liquid feed nozzle, where corrosion is more significant.

Tray tower design for SWS. Most SWS systems are designed with trayed towers. Trays can be designed to be fouling resistant. However, even in trayed systems, the selection of an inappropriate tray can lead to poor performance of the SWS. General recommendations for SWS tray selection include:

- Trays should be a fixed-valve type and should be designed for vapor to flow horizontally out of the valves to minimize bridging of deposits on the fixed valves. Tray designs like this are readily available from major distillation internals vendors. Sieve trays can also be fouling resistant in some services. For example, the authors know of acceptable sieve tray use in aqueous systems with solid particles circulating (i.e., in slurry service). However, sieve trays have shown severe fouling in SWS service, with vapor flow area decreasing by as much as 90%. This may be due to the vertical direction of the vapor leaving the tray deck, which allows precipitation on the tray deck that can foul the tray.[12,13] **FIG. 3** shows an example of fouling that can occur on sieve trays in SWS service. This level of fouling occurred over a typical SWS run between maintenance intervals of 5 mos.[13]
- All trays should be constructed of 300-series stainless steel or better. Depending on the sour water processing demand, the tower may be too small for personnel to physically install the trays. In this instance, cartridge trays could be used.
- If a pumparound system is installed, the trays used for the pumparound loop should not be counted as active mass transfer trays.
- In a fouling service like with an SWS, the downcomers are potential traps for fouling material and can adversely affect the capacity of a tray. Special designs that are available from the internals suppliers to address fouling material in the downcomers should be used.

Tray efficiency is reported in several different ranges for SWS service, but generally will vary from 15%–50% depending on different factors. The number of trays present in the SWS will then also vary widely; a common range on the number of actual trays installed may be 20–60. On a 24-in. spacing, this translates to 40 ft–120 ft of height for trays, which may mean an SWS as tall as 150 ft in some applications.

From the authors' discussions with a few refinery subject matter experts (SMEs), a rough rule of thumb for design tray efficiency in an SWS is 3 actual trays per 1 theoretical stage or 33% efficiency. This is probably a conservatively low efficiency for most systems. For example, one SME acknowledged this rule of thumb, but noted that actual tray efficiencies experienced in sour water service (presumably well designed) were closer to 50%. In designing a trayed system, one could probably rely on the rule of thumb to result in a system with significant overdesign built in. For a less conservative and more economical design, careful engineering analysis and comparison with the actual performance of other similar SWS systems is needed.

Some factors that influence the efficiency of the trays include the following:

- Perhaps most importantly, tray efficiency is a chemical engineering factor that is applied to equilibrium-based designs to account for the fact that operating trays do not reach equilibrium conditions. Hatcher and Weiland[14] show that component efficiencies for H_2S and NH_3 will vary widely across the stripper column, and could depend heavily upon the stripped water specification for the water leaving the bottom of the stripper, the steam rate to the stripper or reboiler, etc. Therefore, the efficiency of the tray is not a static value throughout the stripper, varies from one component to another and may be different in the top of the tower than it is in the bottom. To reduce uncertainty, the designer may need to do a more rigorous simulation of the column.
- The most important consideration for SWSs is that they work reliably. As a result, designs for SWSs tend to be conservative. One way of introducing conservatism into the SWS design is to specify a low tray efficiency that, when installed, will allow the stripper to operate and meet specifications in a more heavily fouled state and to meet specifications if the impurities present in the sour water exceed the initial design values. If there is access to an existing stripper in the same service, then operating data can be obtained to verify the design parameters.
- In many instances, the actual composition of the sour water feeding the SWS system may be uncertain. Crude oil slates in a refinery can change frequently, with the nitrogen and sulfur contents

FIG. 3. Fouling of sieve tray in SWS service.[13]

FIG. 4. Example of tray fouling in SWS service.[13]

of the different hydrocarbon changing over time as the refinery processes different crudes, or different unit operations are added to the refinery. Ideally, the SWS can handle most or all these changes without major modifications to the stripper. A conservative estimate of tray efficiency will provide more flexibility in the design to account for the uncertainty of the feed composition.

As previously mentioned, numerous SMEs use an initial rule-of-thumb tray efficiency of 33%, or three actual trays in the SWS for every equilibrium stage in the process simulation. To further refine the cost estimate or proceed with detailed design, it may be prudent to build a mass-transfer rate model of the SWS. This can be more easily done once the column internals have been selected, since accurate information about the tray—such as weir height, active tray area, etc.—are critical to building an accurate mass-transfer rate model. Reliable estimates of the sour water composition will also be necessary to help ensure the appropriateness of the SWS design.

Another important factor in the design of the column is tray hydraulics. The actual hydraulics on the tray is dependent on the tray device such as fixed-valve trays. The number of valves and size of the opening is important to maintain liquid on the tray and get proper contacting of the vapor and liquid; thus, the proper operating range for the design becomes important. If the trays are overdesigned, then the tray may weep or dump liquid, resulting in poor operation. The design must account for the low end, as well as the high end of operations. One reason 24-in. tray spacing is often used is to give more capacity, especially when fouling or foaming is expected.

Even when the designer is confident in the design of the column, some additional precautions are recommended. These include:

- NH_3 will be the more difficult component to remove in most sour water streams. NH_3 has a high affinity for water and will almost always strip out of the sour water after the H_2S is almost completely removed. It is possible to reach a stripped water condition where the remaining NH_3 is fixed in the stripped water, meaning that it is bound to a non-volatile or strong acid in the stripped water and will not come out of solution regardless of the energy input into the bottom of the column. In this case, it is prudent to install a nozzle in the lower section of the column to allow for caustic addition, if necessary, under some or all conditions. The strong base will displace the NH_3 and allow it to be more easily stripped from the column. By placing the nozzle in the lower section of the tower, the caustic will not interfere with H_2S stripping.
- Although trays can be designed for fouling service, some reduction in efficiency will likely be noticed over time. Even with adequate solids removal and hydrocarbon phase removal, some fraction of these materials will enter the column periodically. Some slightly-water-soluble hydrocarbons may enter the tower and precipitate in the lower section of the SWS as the water heats to near boiling. Other salts may be present in the water that precipitate in the higher temperature areas of the SWS. Adequate access to the column for quick maintenance and some additional design margin may be prudent to address fouling concerns. **FIG. 4.** shows an example of fouling that can occur in SWS service over a 5-mos period of operation, which corresponded to the 10%–15% reduction in vapor flow area noted by the authors.[12,13]

Takeaways. Stripping sour water is a demanding process in a refinery or gas treating facility. The sour water will contain a multitude of contaminants in addition to the $NH_3$and H_2S stripped out of the water in the process. These contaminants make reliable operation of the SWS a challenge, but one that can be realized with appropriate design of the SWS and the equipment that surrounds it. Proper sizing and level control of the three-phase separators in the sour water system are critical to removing contaminants—such as hydrocarbons—that can severely impact SWS performance by causing fouling and foaming in the column. Solids filtration and liquid/liquid coalescing equipment should also be considered as additional means to further clean the sour water prior to the stripper. The SWS needs to be designed to handle variations in inlet feed composition and flowrates, as well as allow a margin for fouling and foaming. The selection of tray internals should consider the severity of the service and the presence (or absence) of good sour water cleanup steps prior to the stripper. The tray design should take into consideration fouling, efficiency and hydraulics, among other factors.

Part 2. Part 2 discusses the design of packed tower SWS and details operating problems that can occur in an SWS system. HP

NOTE

This article was originally prepared for the Brimstone Sulfur Recovery Symposium. It has been edited and separated into two parts for publication in *Hydrocarbon Processing.*

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Maximize margins in a light naphtha isomerization unit by producing additional C_6 products

The increasing demand for more efficient and low-emissions fuels due to stringent environmental policies and growing environmental awareness is leading refiners to find options to enhance the research octane number (RON) of the final product. This has made the isomerization process an important and intrinsic part of almost all refineries.

The isomerization process is not only capable of upgrading the octane number of naphtha fractions—particularly C_5 and C_6—but also simultaneously reducing the benzene content of naphtha by saturation of the benzene fraction. This efficiently converts low-grade, straight-run naphtha to more marketable and valued product due to the improved RON. Isomerization is preferred not only because it is simple and cost effective for octane enhancement as compared to other octane-improving processes, but also because it produces isomerate product with very low sulfur and benzene, making it an ideal blending component in the refinery gasoline pool.

Structurally, the straight-chain paraffins get converted into their branched-chain isomers, which improves the RON of the isomerate and has increased the popularity of the process. Technology companies offer various options of isomerization processes, whether once-through or recycle. The benefits of improved RON of the final product paired with the CAPEX and OPEX involved in revamps govern refiners' decisions for their isomerization units.

A few examples of this transformation of a compound into any of its isomeric forms—which have the same chemical composition but different structures and physical and chemical properties—through the process of isomerization are depicted in **FIG. 1.**

As the isomerization process is mildly exothermic, low temperatures favor the reaction in a forward direction; therefore, highly active catalyst are employed. To avoid the formation of olefins in a low-temperature process, the feed to the isomerization plant is premixed with hydrogen (H_2). Processes are capable of upgrading low-octane C_5/C_6 streams to products with octane ranging from 80 RON–93 RON. It has been observed that once-through processes can produce product from 80 RON–84 RON, while recycle processes with deisopentanizer and deisohexanizer columns can give products with an RON as high as 93.

Process flow scheme in an isomerization unit with recycle. Besides the isomerization reactor, a typical isomerization unit consists of three columns. The deisopentanizer (DIP) column stands at the front end of the unit (before the reactor), while the stabilizer and the deisohexanizer (DIH) columns are at the back end of the unit (i.e., after the reactor). The product stream from the isomerization unit is stabilized and then sent to the DIH column. The column splits the isomerate stream into three streams (i.e., the light isomerate, DIH recycle and heavy isomerate). The light isomerate and the heavy isomerate streams are combined and sent to the battery limits for storage. The DIH recycle stream is sent back to the isomeri-

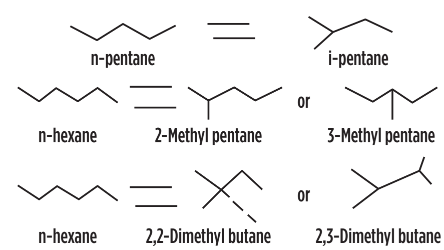

FIG. 1. Primary reactions in an isomerization process.

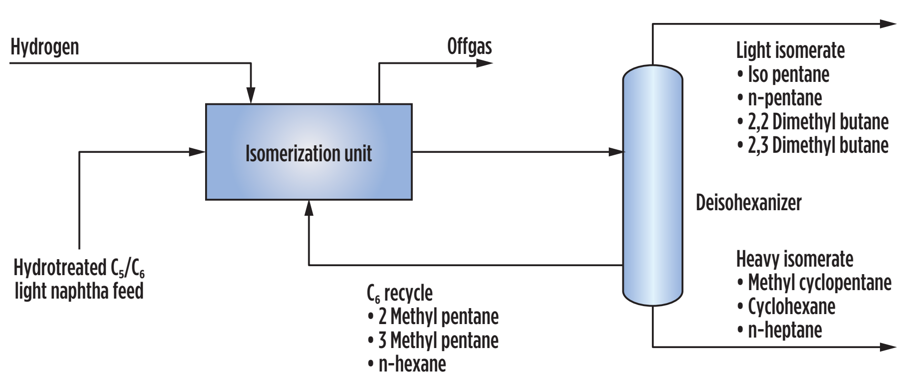

FIG. 2. Block flow diagram of a typical light naphtha isomerization unit.

zation reactor. The block flow diagram of a typical isomerization unit is shown in **FIG. 2,** as are the compositions of the light isomerate and the heavy isomerate stream.

The light isomerate is primarily composed of four components: isopentane, N-pentane, 2-methyl butane (2MB) and 3-methyl butane (3MB). The focus on improving the RON of this stream has made technology companies invest time and money for further improvements in processes and catalysts. The recycle stream that is sent back to the reactor is mainly a mixture of 2-methyl pentanes (2MP), 3-methyl pentanes (3MP) and N-hexane. The lower the quantities of 2MP and 3MP in the recycle stream, there is an increased tendency of the equilibrium to shift in a direction to lower values of 2MB and 3MB in the product stream. These are critical components that contribute to the RON of the total isomerate. Therefore, the recycle stream should have requisite amount of 2MP and 3MP to obtain desired product specifications. However, this eventually leads to a buildup of the third component of the recycle stream (N-hexane) in the recycle loop, affecting the throughput of the isomerization reactor and creating a bottleneck when it comes to capacity augmentation.

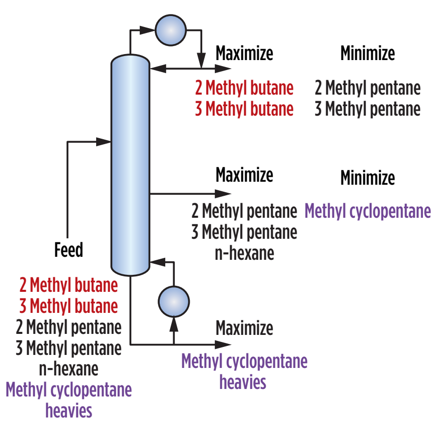

FIG. 3. A closer look at a DIH column component split.

This potential bottleneck led to the novel idea of drawing N-hexane out of the recycle loop and using it to make a few value-added products. N-hexane drawn from the loop can be converted to marketable products, such as food-grade/polymer-grade/pharma-grade hexanes and isohexanes. Not only do these marketable products bring in additional revenue to the facility, but as the recycle to the isomerization reactor decreases, more feed can be pushed through the reactor. This is an added benefit for facilities, particularly where the isomerization unit is bottlenecked.

FIG. 3 further describes the compositions of feed and product streams of the DIH column.

ALTERNATE C_6 PRODUCTS FROM THE ISOM UNIT

The recycle stream in an isomerization unit can be used to produce a variety of C_6 products that are widely used in the industry and are produced through alternate processing routes:

- **Food-grade hexane (FGH):** Food-grade hexane is a colorless solvent primarily used in the extraction of edible oils. This calls for very high purity levels of hexane, followed by safe and careful storage. It also finds usage in the preparation of rubber adhesives, can sealing compounds, etc.
- **Polymer-grade hexane (PGH):** PGH is a fast evaporating hydrocarbon solvent that consists essentially of hexane isomers. A concentration of approximately 40% makes n-hexane the major component in this mixture. PGH is used as a polymerization medium and in the manufacture of catalysts.
- **Isohexane:** This compound, which can also be drawn from the recycle stream, is a solvent used in industrial, professional and consumer applications, such as a manufacturing process solvent, metal working and coatings. It is not sold directly to the public for general consumer uses; however, this product may be an ingredient in consumer and commercial product applications, such as cleaning agents and coatings.
- **Special boiling point (SBP) spirit:** Depending on market demand, SBP spirit 55/115 can also be produced from the recycle stream. It is used in the rubber industry, particularly during the process of vulcanization in tire manufacturing or in preparation of certain rubber mixes, cements and adhesives. It is also used as a thinner for varnish, paint and printing inks formulation where quick drying is required, and as diluent for lacquer, enamels and high-grade leather drops.

TABLE 1 provides the typical specifications of the products discussed here.

Dividing wall columns (DWCs). DWCs have gained popularity both in grassroots and revamps in the petrochemical industry. The technology works on improving conventional distillation columns, which are the most energy intensive areas in the refining and chemical industries. Facilities are reaping maximum benefits from this technology, and many refineries are undertaking revamps to harness the benefits of DWCs in areas that otherwise are bottlenecked.

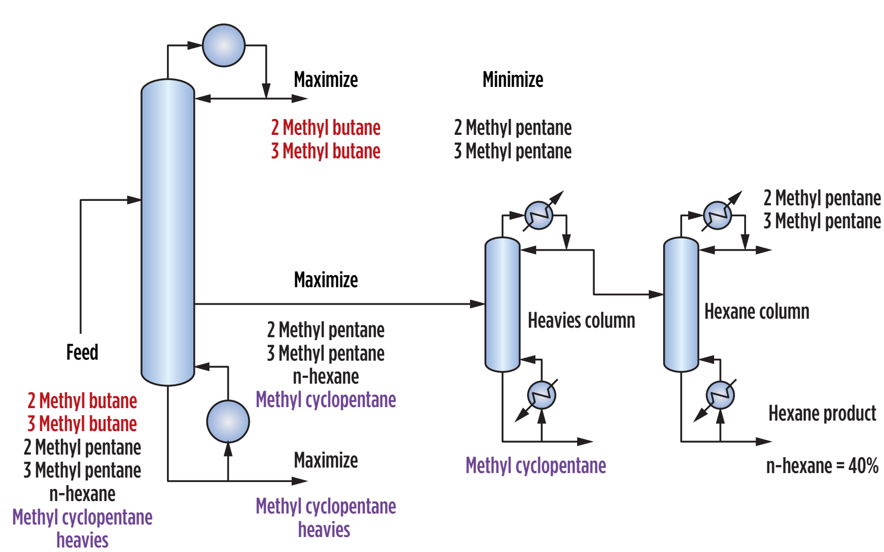

FIG. 4. Typical configuration for producing FGH using a conventional sequence of columns in an isomerization unit.

Revamps of conventional columns to DWCs can provide the following benefits:

- Ideal alternative for revamp of side-cut columns when high purity is required from the three product streams
- Lower footprint as equipment count is reduced by half
- CAPEX and OPEX can be reduced by approximately 20%–50%.

Structurally, the exterior of a DWC looks like a conventional distillation column, but inside a defining wall in the column separates the tower into two sections, creating different fractionation zones. The zone in the column where the feed is introduced works to effectively separate the heaviest and the lightest key. Because this wall removes the intrinsic mixing that takes place in the conventional column by creating different separation zones, these columns are thermodynamically more efficient compared to their counterparts—therefore providing benefits in terms of operating cost.

DWCs in a DIH column for producing C_6 cut. As demand for C_6 products surged, refiners foresaw an additional source of revenue and hurried to generate C_6 product.

The usual way of obtaining FGH from the recycle stream is by installing two new columns post the DIH column. **FIG. 4** shows the typical configuration of producing FGH by the DIH route. In this sequence, two new columns are installed downstream of the isomerization recycle stream to produce FGH.

An attractive alternative to this sequence would be to revamp the existing DIH column using DWC technology to produce four cuts.

For isomerization facilities, the revamp of a DIH column to DWC can have significant benefits. The revamped DIH column produces light and heavy isomerate as top and bottom products, along with FGH and the recycle stream as the other two cuts. **FIG. 5** shows how a middle DWC handles the overlap of the heavy isomerate and the recycle stream, reducing the number of stages required for the desired specifications compared to the conventional column—the spare stages are available in obtaining the fourth cut.

This option of getting four cuts from the DIH column is not only attractive in terms of lower CAPEX and OPEX, but is flexible as the column is capable of operating in two modes: the FGH mode, in which the column will produce a fourth cut of FGH; and the DIH mode, in which the column operates in conventional mode with recycle to the isomerization unit without FGH production. To produce the fourth cut, the alignment of the wall inside the column is customized to meet the desired product specifications, quantities and also target to minimize the heat loads. The advantages of this process are sufficient to prompt facilities to utilize it for beneficial production of FGH.

FIG. 6 shows the process flow and the components of the four cuts of the DIH column post revamp. Benefits include:

- Energy consumption is 30% less than the conventional column sequence.
- With the drawing of FGH (i.e., n-hexane from the recycle stream

TABLE 1. Specifications for C_6 products

Property	Units	FGH	PGH	SBP	Isohexane
Color	Saybolt		Min. 30	Min. 25	Min. 30
Density (at 20°C)	kg/m³	0.660–0.687	0.660–0.687		0.665–0.686
Moisture	mg/kg	50	Max. 100		Max. 100
Bromine index	mg Br/100g	Max. 50	Max. 10		Max. 5
Refractive index		1.375–1.384	1.375–1.384	-	1.373
Cu Strip Cor. for 3 hr at 50°C			< 1	< 1	< 1
Doctor test		–	Negative	–	Negative
Distillation range					
Initial boiling point	°C	65	64	50	59
Final boiling point	°C	69	70	120	63
Residue on evaporation	mg/100 ml		5	5	1
Components					
N-pentane		–	–	–	Max. 1
N-hexane	wt%	Min. 40	Min. 44		Max. 5
Isohexane	wt%	30–45			Min. 95
Methyl cyclo pentane	wt%	Max. 20			
Cyclo hexane	wt%	Max. 3			
Benzene	ppmwt	Max. 500	Max. 3		Max. 100
Aromatics	ppmwt		Max. 10	Max. 3,500	
Lead as Pb	mg/kg	Max. 1	Max. 1		
Tota sulfur	mg/kg	Max. 5	Max. 2		Max. 1

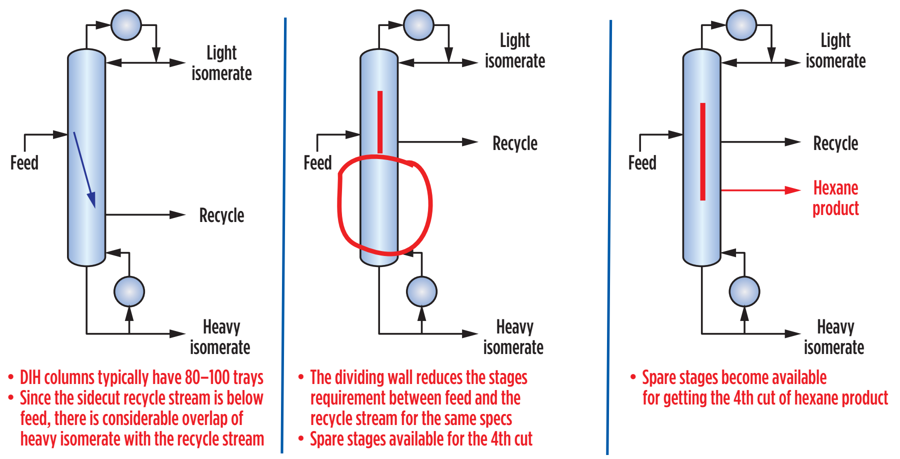

FIG. 5. Use of DWC technology for a revamp of a DIH.

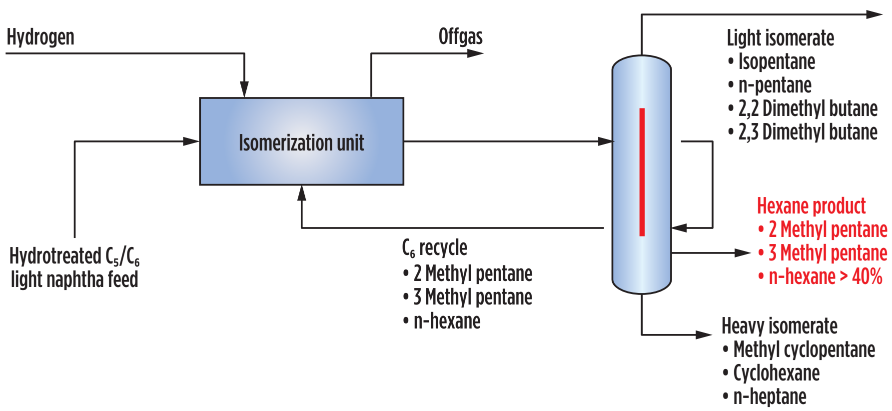

FIG. 6. Hexane production in an isomerization unit using DWC technology.

TABLE 3. Value addition in an isomerization unit with additional FGH production

	Raw materials and products			Economics		
Items	**Unit**	**Existing**	**Revamp of DIH column to DWC**	**Unit**	**Existing**	**Revamp of DIH column to DWC**
Light naphtha feed	t/hr	39.14	47.34	$/hr	20,392	24,664
Hydrogen feed	t/hr	1.62	1.64	$/hr	1,011	1,022
Steam consumption	t/hr	27.18	43.92	$/hr	655	1,059
Cooling water consumption	m^3/hr	662	662	$/hr	30	30
Power consumption	MW	461.6	513.6	$/hr	49	54
Products				$/hr		
Light and heavy isomerate	t/hr	35.42	35.42	$/hr	21,890	21,890
FGH	t/hr	0	8.2	$/hr	0	5,521
LPG	t/hr	3.72	3.72	$/hr	2,107	2,107
Net benefit (product price—cost of raw material and utilities)				$/hr	1,860	2,689
				$MM/yr	14.9	21.5

TABLE 4. Project payback

Total project investment	$3.8 MM
Net revenue after revamp to DWC	$6.6 MM
Payback	6.9 mos

TABLE 2. Cost basis for economic evaluation

Stream factor	8,000 hr
MP steam	24.1 $/t
Power cost	105.8 $/MW
Light naphtha feed	521.0 $/t
Hydrogen feed	0.623 $/t
Light/heavy isomerate	618.1 $/t
FGH	673.3 $/t
LPG	566.4 $/t
Cooling water	0.037 $/$m^3$

as the fourth cut), the recycle rate to the isomerization reactor is reduced. This helps in pushing more feed through the reactor and is helpful in capacity augmentation.

C_6 production from other routes compared to DWC in isomerization unit. C_6 products are commonly produced via extraction by dearomatization of light naphtha fraction post hydrotreating. In this process, sulfolane is used as a solvent to remove aromatics from the C_6 cut. Although this technology is widely used, it has shortcomings when compared with the production of FGH post the isomerization unit because:

- The latter does not require the installation of an aromatics removal unit (ARU) to get dearomatized naphtha.
- When FGH is produced from an isomerization unit stream (e.g., from the DIH column), no additional column is required, while the former requires columns in series.
- Not only does the revamp to DWC produce FGH from the DIH column bring additional revenue, it also debottlenecks the isomerization unit in terms of capacity by at least 15%–25%.
- There is an increase in total octane barrel by the route of FGH production through isomerization.

Case study. The case study presented here is based on an operator in Asia. The refinery has a light naphtha isomerization unit processing 39 t/hr of fresh feed with an isomerate product RON of 88.

Cost basis analysis and typical payback for the unit are summarized in **TABLE 3,** providing the investments vs. the total revenue post revamping a DIH column into a DWC for the facility. Net profitability is calculated based on the margin difference between new FGH and isomerization products. The project payback is detailed in **TABLE 4.**

The following conclusions can be drawn from the case study:

- Revenue increased by producing high-value hexane products
- The RON of isomerate products remains unchanged
- The isomerization unit can process an additional 15%–25% of fresh light naphtha feed without any modifications to the reactor section
- Typical project payback is 5 mos to < 1 yr.

Takeaway. Refineries are taking up the production of food-grade/pharma-grade hexane through the use of DWC technology by revamping the DIH column to a four-cut column. This is a promising venture, requiring some modification in the existing DIH column in terms of the installation of a dividing wall and change limited to a few trays. The revamp can be done easily in 20 d, which are typically available during the annual shutdown in the facility. With rising demand for C_6 products, this is an attractive venture. HP

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Troubleshoot flooding problems in a crude distillation column

Crude oil is separated into more valuable products, such as naphtha, kerosene, light diesel, heavy diesel and atmospheric residue, in crude distillation units (CDUs). CDUs must be operated under optimized, stable conditions to provide on-spec products and high refinery profits. Unfortunately, for older CDUs, expected operating conditions might not be achieved due to design limitations of the main equipment. Emergency shutdowns might result in other problems that cannot be discerned unless the main fractionation column is inspected.

The 59-yr-old CDU at Tüpraş' İzmit refinery suffered from temperature profile variation of the atmospheric distillation column after the unit restarted following an emergency shutdown. The variation in column temperature profile led to unstable and inefficient operation, reduced feed rate and off-spec products.

The cause of the issue was investigated step by step to find a solution to the problem. Process data indicated flooding in the column. Optimum working conditions were provided after necessary maintenance work was carried out. In this article, the definition of the problem and the method applied to detect the problem are presented, and the operating conditions provided after the conclusion of maintenance work are discussed.

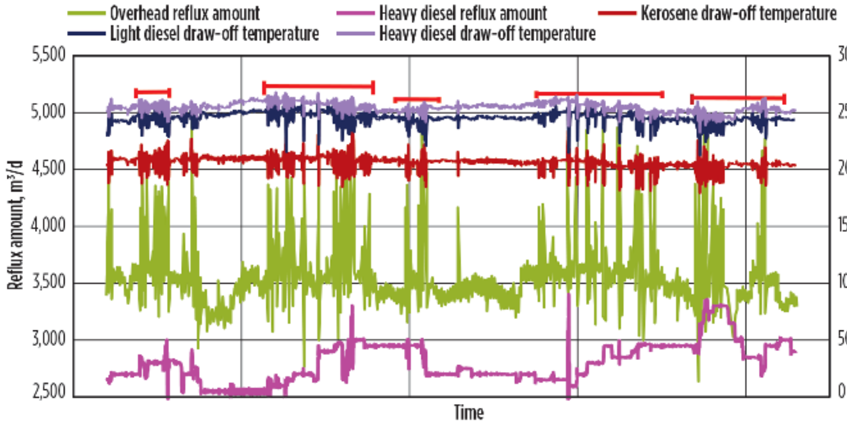

FIG. 1. Reflux amounts and the oscillations in product draw-off temperatures.

Column fault background. The İzmit refinery, which commenced operations in 1961, is one of the largest refineries operated by Tüpraş. After increasing unit capacity and investing in conversion capacity over the years, Tüpraş registered the design capacity of the refinery at 11 MMtpy. The refinery has three CDUs that produce mixtures of LPG, light and heavy naphtha, kerosene, light and heavy diesel, and atmospheric residue.

The oldest CDU has the lowest capacity of the three. It removes salt and water from the crude oil in the desalter section and then separates the crude into products, according to their boiling point differences, in the atmospheric distillation section. LPG and naphtha are sent to the naphtha stabilization section, and atmospheric residue is processed in the vacuum distillation unit (VDU).

The CDU suffered an emergency shutdown and underwent maintenance. Upon restart, it was observed that the temperature profile of the atmospheric distillation column oscillated. This temperature fluctuation limited unit operation, especially during the processing of crude oil with high naphtha. During the turnaround in October 2019, plugged nozzles were observed on the top reflux

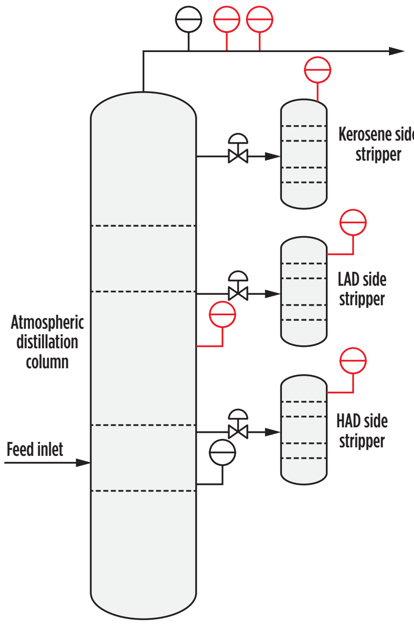

FIG. 2. Locations of installed pressure gauges (in red) and transmitters at the top and flash zones.

distributor, and holes were found in the downcomer where the top reflux discharges. Maintenance carried out on the top reflux system was assumed to be the reason for the oscillation problem. However, the problem continued after the unit was restarted.

To determine the reason for the oscillation problem, the unit was shut down again. This time, it was found that the downcomer of the kerosene drawing area was plugged. Maintenance was performed on this area, and all lines for the atmospheric distillation column were washed.

Problem description. The marked zones in **FIG. 1** indicate the time intervals during which the feed characteristic changes and oscillation occurs. When the top reflux amount rises above a certain value, the temperature oscillation begins. During this oscillation, the change in pressure (ΔP) between the column top pressure and the flash zone pressure increases. This increase in pressure drop revealed the possibility of flooding inside the column.

According to the findings of the first examination, with increased naphtha content in the processed crude, the amount of overhead reflux increases to keep the overhead temperature constant. This causes fluid head to form in the area where flooding is suspected. The liquid level formed exceeds the liquid carrying capacity of the tray at some point, causing it to fall into the lower trays, which makes them cool. This situation creates the oscillation in the product withdrawal temperatures.

A pressure survey was conducted to determine the region through which the column the flooding occurs. Pressure gauges were installed in different zones of the column, and the pressure data from the points shown in **FIG. 2** were recorded twice per shift for one week. The recorded pressure data included both conditions—during oscillation and under operating conditions without oscillation.

The change in crude oil content may lead to an increase in the amount of overhead reflux, depending on the ratio of naphtha cut in the feed. **FIG. 3** represents the change in pressure drop value with respect to overhead reflux in the column. It has been observed that when the overhead reflux exceeds a certain level, the difference between the column overhead pressure and the flash zone pressure reaches approximately 370 g/cm². It indicates that liquid level accumulated in the column gives rise to excessive pressure drop through the column, since the theoretical and anticipated pressure drop is around 200 g/cm²–300 g/cm².

FIG. 4 demonstrates the change in pressure drop value obtained with the recorded pressure data from the transmitter on the column top and from the pressure gauge installed on the kerosene stripper with the amount of reflux. As the top reflux amount rises, the difference between the column top and the kerosene stripper pressure reaches 200 g/cm²–220 g/cm². Considering the number of trays in this region, these values correspond to 3–4 times the expected pressure drop value. This indicates that the suspected flooding in the column takes place in a region between the kerosene withdrawal zone and the top line of the column.

FIG. 5 represents the change of pressure drop values between the kerosene

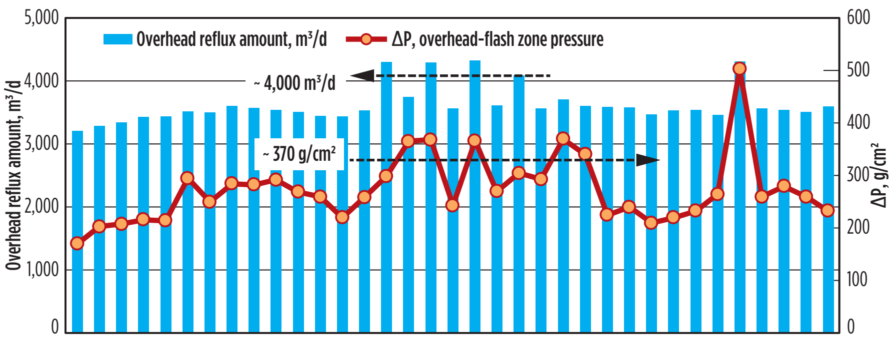

FIG. 3. The ΔP through the column and the overhead reflux amount.

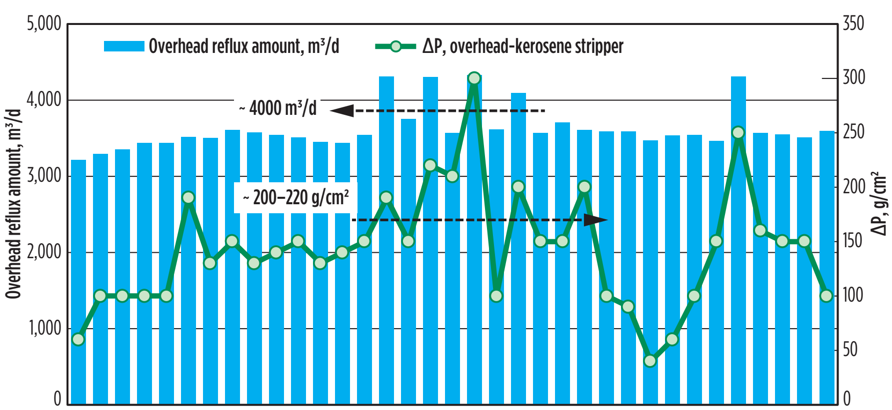

FIG. 4. The ΔP between the overhead and kerosene stripper and the overhead reflux amount.

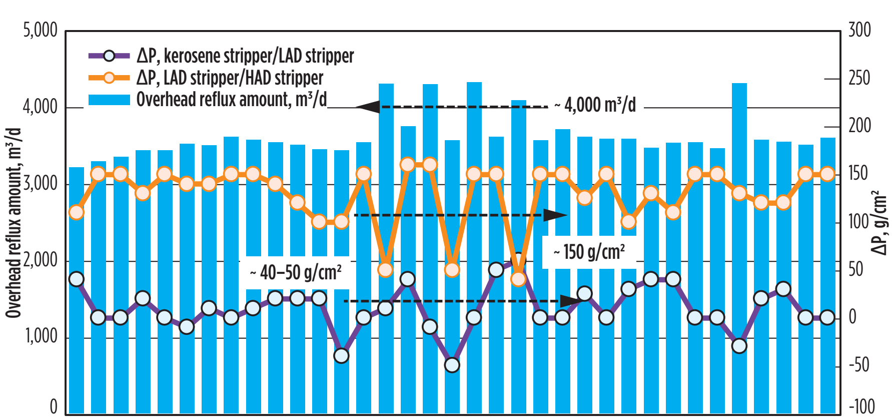

FIG. 5. The ΔP between the kerosene and LAD stripper and the LAD and HAD stripper vs. the overhead reflux amount.

and LAD stripper and the LAD and HAD stripper with respect to the top reflux rate to column. When FIG. 4 and FIG. 5 are examined together, it can be seen that when the liquid level that causes flooding in the kerosene region starts to form, the amount of liquid that should be in the trays in the LAD region decreases because there is not enough distribution in the trays in the kerosene region. For this reason, the pressure drop between the kerosene stripper and the LAD stripper decreases considerably, which indicates that the trays in this area are becoming dry due to insufficient liquid level. However, despite the drying of the trays in the LAD region, when the pressure drop values between the LAD and HAD regions are examined, it is seen that there is sufficient fluid level in this region. HADPA, the second reflux given to the column, returns to the HAD region of the column after completing the heat transfer cycle and provides the liquid-vapor balance in this region.

Based on these evaluations, the root cause of the high ΔP problem in the kerosene region was identified as flooding, which may have occurred due to a blockage in this region. A column control plan was created to focus on the detection of blockage in these areas. The studies carried out during maintenance are explained in detail in the following section.

Troubleshooting and performance evaluation. According to the pressure survey and trends outlined in the previous section, a 15-d, partial maintenance was planned to include the atmospheric distillation column and side strippers.

After the columns were steamed out and washed, beginning from the top of the atmospheric column, an investigation into the source of the problem was undertaken. After controlling all the trays and downcomers between the top and kerosene section, a blockage was detected on the downcomer of the previous tray of the kerosene draw tray, shown in yellow in FIG. 6.

A sample was collected and sent to the lab for examination to determine the source of the contamination. The kerosene upper tray is where the kerosene stream should flow from the relevant downcomer to the chimney tray's canal, where the kerosene stream is drawn from the column. The contamination is the reason for the liquid level accumulation and, therefore, the flooding in this area.

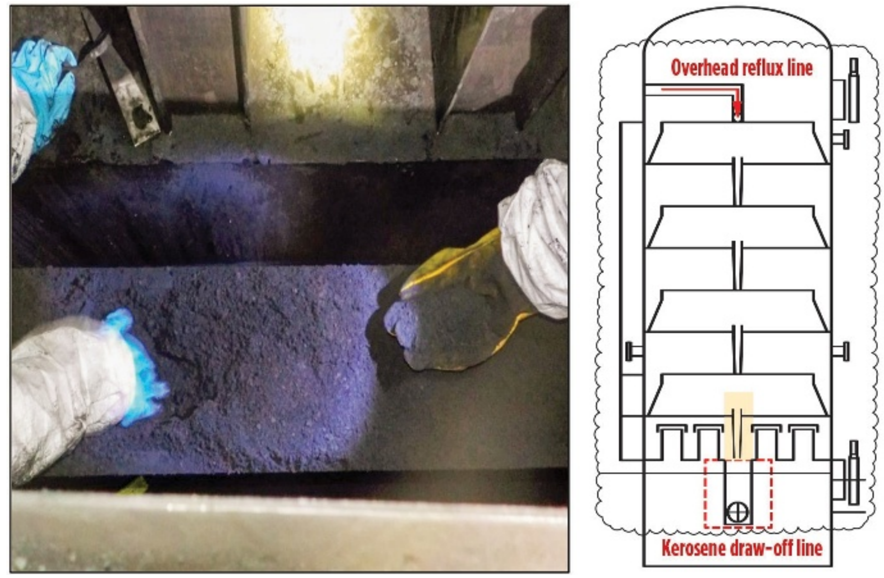

FIG. 6. Blockage in the downcomer of the kerosene tray.

FIG. 7. Accumulated fouling in the kerosene downcomer.

FIG. 7 shows the fouling sample taken from the downcomer. The analyzed sample was determined to contain 77% inorganic and 17% organic matter. In the analysis of the inorganic matter, the pollution mostly consisted of Fe, S and Ni elements. As a result of this analysis, the root cause of the pollution in the downcomer was determined to be the accumulated corrosion pollution, which could not be inspected during turnaround since the upper tray must be removed to do it.

To fully clean the deposit in the downcomer, its lower canal, draw section and upper tray were removed from the corners. Detailed cleaning was applied on the trays and canal, after a water wash. The internals and trays of the column have been controlled since this cleaning, and no other major blockage or deposit has been detected. The flow path is shown in FIG. 8.

Since the blockage was seen in the kerosene draw section of the main column, the kerosene side stripper was also opened, inspected and controlled.

FIG. 8. Tray downcomer connection and the flow path.

FIG. 9. Kerosene stripper trays and contamination.

During the inspection, a uniform contamination deposit was found on the trays and on the reboiler exchanger shell side of the stripper, as shown in FIG. 9. During the shutdown of the unit, the atmospheric distillation column was controlled from top to bottom, the side strippers were opened and checked for deposits, and all of the drawing lines and internals were cleaned both manually and with water. The CDU was then successfully restarted and closely monitored. After enough data was collected from the running unit, the next step was to compare before-and-after values of the entire system.

It is important to clean the column and to maintain steam-out during emergency shutdown of the unit to guarantee operational efficiency after maintenance is performed.

As shown in FIG. 10, production draw temperatures (especially kerosene draw temperatures) have stopped oscillating and started to follow a straight line controlled by column dynamics and feed compositions, as desired. The atmospheric column is producing on-spec product. The overhead reflux value has also improved since the gas and liquid flows in the column have become uniform.

As shown in FIG. 11, pressure values during the oscillation in the column were critically high between the top and flash sections, but dramatically low between the light diesel and heavy diesel parts of the column. After maintenance, differences in pressure values, shown in FIG. 11, indicate that the pressure was stabilized.

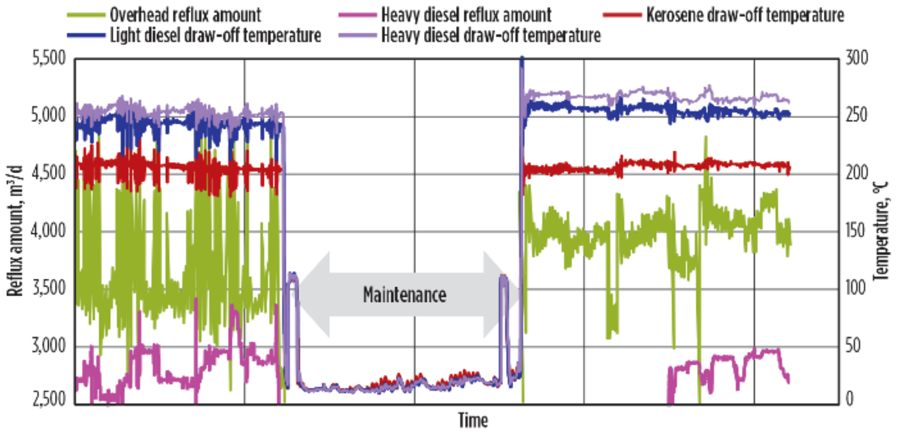

FIG. 10. Before and after values of the overhead reflux and draw temperatures.

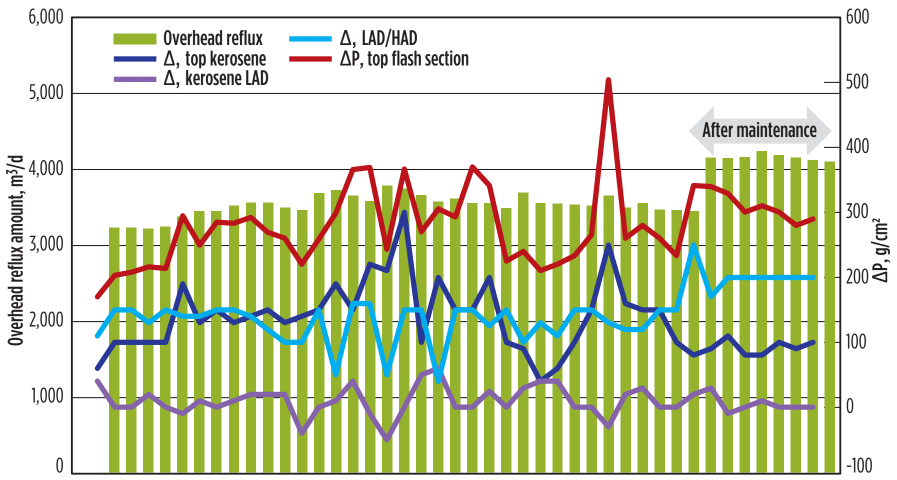

FIG. 11. Compared pressure values along the column.

Takeaway. The blockage was detected at the downcomer of the kerosene drawing section of the atmospheric distillation column. This blockage caused an increase in pressure at the top of column, an increase in temperature (depending on an instant rise in top load for lighter crude) and an increase in top reflux due to a high top load. These problems collectively resulted in temperature oscillation in the column. The unit did not operate as expected at the maximum unit charge.

When the contamination of the downcomer at the kerosene drawing section was examined, the content of this contamination was observed as 17% organic and 77% inorganic material. The organic part was related to charge content, and the inorganic part resulted from accumulation in the kerosene downcomer during turnaround blasting operations in the column.

As learned from this study, it is important to clean the column and to maintain steam-out during emergency shutdown of the unit to guarantee operational efficiency after maintenance is performed. In addition, the control of the column and its internals is crucial. During column control, the cleaning of the downcomer sections and drawing lines must be provided, and the drawing lines must be washed until every line is clean. HP

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A compliant solution for repairing corroded acid lines with composite materials

Composite materials have been utilized for the repair of corroded or damaged piping in refineries, chemical plants and other highly aggressive operating and production plants around the world for decades. With advancements in available technologies, along with organized industry standards, this upward trend has not only continued, but has required that composite technologies push the boundaries further.

Because of the demanding conditions found in most facilities, one area of need that has been growing is for an engineered composite repair system (ECRS) that is compliant and effective with highly acidic mediums found within piping systems. Many requests for compatibility information between the pipe contents and the composite repair materials have been fielded from the industry, with sulfuric acid in high concentrations being a routine chemical in question. Due to the increasing demand for ECRSs, new formulations and fibers for composite repair systems were reviewed for feasibility and tested for material properties to determine their effectiveness and performance.

Much research and subsequent testing programs were completed to develop a specialty polymer formulation that could meet the needs of the industry, and meet qualification requirements, when used in conditions that are highly acidic in nature. This article will present the testing results, capabilities and qualifications of this advanced ECRS.

Background. As ECRSs have gained more recognition and acceptance as a reliable and beneficial repair alternative within the refining and chemical processing industry, continued advancements in materials and capabilities have also allowed for a greater range of usage—thanks in part to the development and implementation of an ASME standard (ASME PCC-2 Article 4.1) in 2006, which provides industry a great deal of guidance on material testing, qualification and design for composite repair systems. One such advancement has been in the area of chemical compatibility, specifically for the use of composites to be compatible with sulfuric acid at high concentrations. As shown in **FIG. 1,** there are many common uses for sulfuric acid across a variety of industries, so the demand for a repair system that can be compatible to this aggressive acid is apparent.

The wide-reaching usage of sulfuric acid and its economic impact are both major reasons why ECRSs are needed. According to Grand View Research, the global sulfuric acid market in 2016 was approximately $10.1 B, which is forecast to increase to $13.45 B by 2025.

With such a vast market for this raw material, it is a clear indicator that a composite repair system with compatibility would be highly beneficial. However, in many cases, the issue is not with the chemical overall, but with the concentrations at which it is utilized in facilities. Since composite repair systems are being used routinely in the oil and gas industry, it was only natural that compatibility—especially at higher concentrations—would be one of the main criteria for ECRS development. While there are some composite repair systems available that are compatible with sulfuric acid at lower concentrations, simply due to the nature of most epoxy polymers, the higher concentrations and temperatures above the standard ASTM testing conditions of 24°C (75°F) are routinely encountered in the field.

With this information, knowledge and experience in mind, a program was developed to research and test for a new composite repair system that could withstand submersion in sulfuric acid at a 98% concentration level. Industry partners have worked with the manufacturer to provide valuable insight into the specific concentrations of concern, as well as the overall, typical operating conditions experienced within their facilities. In addition, information was also provided for other repair alternatives, along with the reasons for developing the

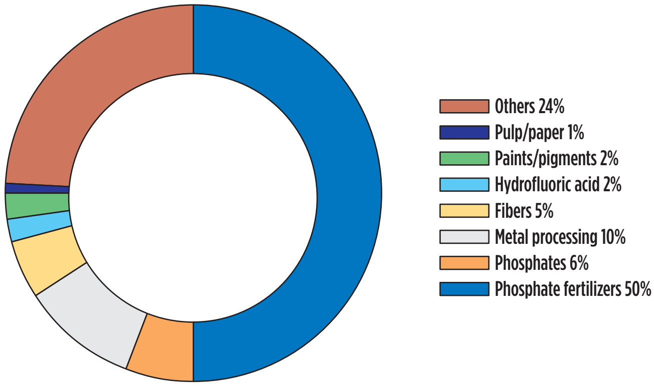

FIG. 1. Common uses of sulfuric acid. Source: The Essential Chemical Industry (online).

compatible composite repair system. These include:

- Mechanical, metallic clamp/patch/enclosure: Reasons for using a compatible composite repair system include:
  - Cost—This option can be costly, depending on the full scope of repair.
  - Limitation on size—This option can have limitations based on the size of pipe requiring repair, including its overall weight.
  - Lead times—This option can be associated with long lead times, depending on the scope of repair.
- Cut and replace: A reason for using a compatible composite repair system includes:
  - Downtime—Time spent out of operation for this option can be extremely costly to the facility due to loss of production.
- Existing composite repair systems: Reasons for using a compatible composite repair system include:
  - Compatibility—Most existing, commercially available composite repair systems are not compatible (or not proven to be compatible) with sulfuric acid at concentrations above 40% or temperatures above 24°C (75°F).
  - Testing—Most existing, commercially available composite repair systems do not have the physical testing in place to validate claims of compatibility in operating conditions.

Development plan. Commercially available epoxy systems were reviewed for potential inclusion in the testing program; however, despite claims of compatibility, there were other hurdles that prevented them from being considered. The correct selection and combination of the epoxy resin and the hardener components determine the final characteristics and suitability of the system for a given environment, and, as such, a set of criteria was developed for review of formulations.

TABLE 1. Gel time test results

Sample no.	Gel time (min)
1	150
2	137.4
3	153
4	154
Average	**148.6**

TABLE 2. Lap shear test results

Sample no.	Lap shear strength (psi)
1	1,150
2	1,140
3	950
4	1,132
5	1,023
6	1,307
7	1,266
8	1,295
Average	**1,158**

A newly required epoxy resin formulation was to be designed for use as both a primer and saturant on repairs, and to meet recommended operational conditions. Additionally, the chosen fibers had to be able to withstand the conditions. When a corrosive chemical comes into direct contact with a fiber, if the wrong type and grade of fiber are selected, then the chemical can degrade the fiber and destroy the resin bond, resulting in a significant reduction in structural properties. Due to known reaction levels between sulfuric acid and carbon fibers, a glass fiber was chosen for the new system reinforcement.

Among the primary goals that a development project for the repair system should include are:

1. Glass transition temperature of 130°C (266°F) or above
2. Gel time longer than 1 hr
3. Lap shear strength greater than 580 psi (4 MPa)
4. Easy to mix epoxy parts A and B
5. Chemical resistance to sulfuric acid up to 98% concentration.

A stringent formulation and testing process was conducted to achieve the targeted properties through various epoxy formulations. Various concentrations of base resins and advanced hardeners were mixed and tested until the desired sulfuric acid resistance, glass transition temperature (T_g), viscosity and gel times were achieved. Once the primary goal properties were obtained, it was necessary to evaluate and adjust percentages of raw materials to meet all the specific performance goals. Various fabric types, architectures and combinations were tested for sulfuric acid resistance to find the final fiber-reinforced plastic (FRP) makeup most compatible for sulfuric acid environments with concentrations up to 98%. Results of the final formulation testing, along with some developmental discoveries of the system's curing protocols, are provided in the following section. Upon completion of the initial research and evaluation of a suitable composite combination, full qualification testing to the ASME PCC-2 Article 4.1 standard (and, similarly, to the ISO 24817 standard) was completed to fully qualify and characterize the new system and its design properties and capabilities.

Material evaluation. Firstly, a thorough research was conducted to determine the appropriate epoxy formulation to be used that would theoretically perform to the primary goals and

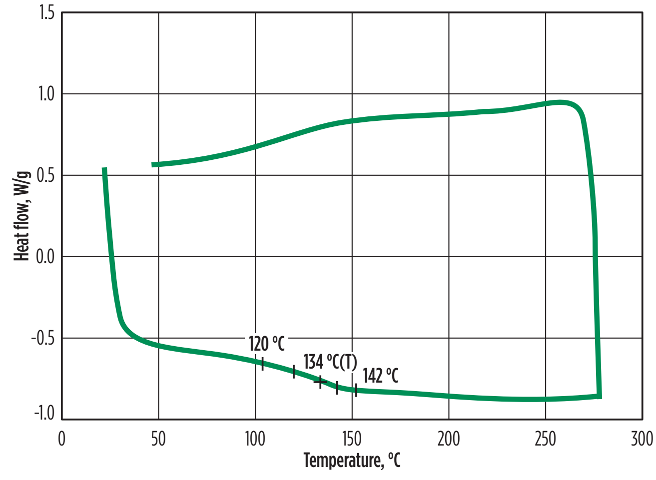

FIG. 2. T_g of epoxy, using DSC.

expectations for the system. Upon completing this exercise and formulating a sample batch of the determined formula, the next steps were performed to confirm that the required gel time, T_g and lap shear values were achieved with the formula.

Gel time determination. Gel time is the length of time that the two-part epoxy takes to gel after full mixing at a specified temperature. This value can be useful to determine a working time of the system so that installers know the amount of time they need to install the product correctly. The test was performed with an 80-gram mass at 24°C (75°F), using a standard laboratory gel timer for four different batches to achieve and confirm repeatability in the results. The average result for the measured gel time was 149 min, demonstrating that the goal was achieved. **TABLE 1** shows the results for the gel time for the different batches.

Lap shear strength determination. Adhesion testing, using a lap shear test, is used for a specific bond strength for the epoxy system to the metallic substrate. The testing was performed according to ASTM D5868-08. Composite plates of the resin and fiber system were bonded to carbon steel plates with the epoxy of the system and, using a universal testing machine, pulled in shear until failure of the adhesion occurred. The type of failure observed was cohesive. **TABLE 2** shows the results of lap shear strength for samples cured at 24°C (75°F). The average value of all eight samples tested was 1,158 psi (8 MPa), doubling the required goal.

T_g determination. The T_g is the temperature range where a thermosetting polymer changes from a hard, rigid (or glass-like) state to a softer, more rubbery state. This is a critical value to know and understand for a composite repair system, as the system must be able to maintain its mechanical properties—consequently, upper temperature limitations should be known to ensure proper function.

The T_g of the polymer being considered was measured using differential scanning calorimetry (DSC) per ASTM E1356. **FIG. 2** shows the T_g of the samples that were subjected to a heat-cool-reheat cycle from 20°C to 260°C, with a ramp of 10°C/min. The T_g obtained was 134°C (273°F), which demonstrated that the goal for this property was achieved [i.e., 130°C (266°F)].

In addition to these physical properties that were evaluated, the "practical" requirement for ease of use was also considered from the beginning. The requirement was for the components to be easy to mix, which meant that the viscosities should not be such that they would be too high, creating a more difficult mixture and causing difficulty in saturating the fiber. There was not a specific target set, but an upper limit of 50,000 centipoise (cps) was the expected maximum value. Upon mixing of the epoxy, the final viscosity was measured to be approximately 25,000 cps, indicating a viscosity that could be successfully implemented within the system.

Once each of these primary goals was achieved, the next step was to test for compatibility with the 98% sulfuric acid solution.

FIG. 3. Epoxy before immersion (left) and after 30 d of immersion (right).

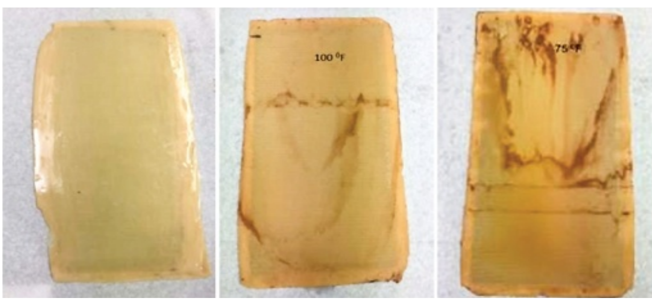

FIG. 4. Composite panel before immersion (left), after 30 d of immersion at a 38°C (100°F) cure temperature (middle) and after 30 d of immersion at a 24°C (75°F) cure temperature (right).

CHEMICAL COMPATIBILITY TESTING FOR 98% SULFURIC ACID

Evaluating the components. Since it is paramount to the system that the polymer can resist changes in its physical properties when exposed to 98% sulfuric acid, this was the subject of the most critical testing. It is important to verify chemical compatibility of the material to ensure that the composite system can retain its mechanical and physical properties after exposure to reagents. Each component of the composite system (the epoxy and the fiber) was first tested individually, then together as the composite system. All specimens were immersed in suitable containers with a 98% sulfuric acid solution.

Different fiber types were immersed in a solution of 98% sulfuric acid at 24°C (75°F) to determine the best fit for use within the composite system. Each of the fiber samples was fully immersed in the 98% sulfuric acid. An examination of each was conducted every 24 hr while immersed. Chemical resistance of the polymer matrix system (a two-part epoxy formulation) was evaluated by measuring change in weight, appearance and Shore D hardness for pure epoxy per ASTM D543-95. After each of the individual components was thoroughly tested and deemed suitable, the full composite system was then evaluated with similar methods of physical property evaluation and by mechanical testing of the tensile properties of test coupons per ASTM D3039.

Creating the test samples. For the testing of fiber, a converted and representative "dry" fabric was tested by cutting the fabric into 6-in. × 6-in. panels. These panels were then submerged and fully immersed into the solution and monitored daily for changes. Fabrics were of various architectures based on commercial availability at the time of testing. The weave style should not influence the compatibility with the medium being tested.

TABLE 3. Dry fiber immersion results

Type of fiber	Fabric weave	Appearance after immersion in 98% sulfuric acid
Fiberglass (E-glass standard)	0°/90° stitched	Fibers broke down after 24 hr
Aramid (aromatic polyamide)	0°/90° plain weave	Fibers broke down after 24 hr
Carbon (standard)	0°/90° stitched	Fibers broke down after 5 d
Carbon/E-glass hybrid	0°/90° plain weave	Fibers broke down after 5 d
Polypropylene (specialty fiber)	0°/90° plain weave	No negative results after 7 d
Specialty fiberglass	0°/90° plain weave	No negative results after 12 d

TABLE 4. Neat epoxy immersion results

Time immersed, d	Hardness change, %	Weight change, %	Surface condition	Resistance rating
7	1.3	–2.8	No change	E
30	1.2	–3.5	Slightly discolored	E

For the epoxy polymer, rectangular-shaped coupons were prepared as neat epoxy bars with approximate dimensions of 76.2 mm × 25.4 mm × 6.4 mm (3 in. × 1 in. × 0.25 in.)—length × width × thickness. The epoxy coupons were cured at 24°C (75°F) for 7 d before being immersed in the solution of 98% sulfuric acid for periods of 7 d and 30 d at the same temperature that was used to cure.

Finally, composite panels of 30.5 cm × 15.25 cm (12 in. × 6 in.) were also prepared with four layers (thickness) of the chosen fiber and the epoxy resin developed for this system. From these panels, tensile coupons were cut (after time spent immersed in the solution) to be tested to determine if any change in mechanical properties occurred after the chemical soak. Panels were post-cured at 38°C (100°F), immersed in the chemical, and then cut into coupon panels for tensile testing.

Results of initial testing. Results of the dry fiber testing indicated only two potential candidates to be used within the final composite system (TABLE 3). Based on these results (along with literature research, economic considerations and manufacturing capabilities), a proprietary, specialty glass fiber—which was developed for use in acidic/corrosive environments—was selected for use within the system.

The results of the neat epoxy coupon samples for this system indicated that the compatibility between the epoxy polymer and the 98% sulfuric acid was excellent (TABLE 4). This rating is from best practice standards for evaluating the resistance of plastics to chemical reagents based on protocol considered by the ASTM D543-95 standard. Resistance ratings were assigned as follows:

- 0%–15% change in properties = Excellent (E)
- 16%–30% change in properties = Good (G)
- 31%–50% change in properties = Acceptable (A)
- > 50% change in properties = Not recommended (NR).

TABLE 5. Composite panel immersion results

Time immersed	Time at temperature curing	Hardness change, %	Weight change, %	Modulus change, %	Surface condition	Resistance rating
7 d	7 d at 38°C (100°F)	0.2	–4.9	–0.21	Slightly discolored	E
7 d	7 d at 24°C (75°F)	0.8	–5.3	–0.8	Discolored	E
1,000 hr	17 hr at 38°C (100°F)	–6.2	10.1	–2.7	Color changed	G
1,000 hr	6 hr at 100°C (212°F)	–0.4	1.5	–0.6	Slightly darkened	E

FIG. 5. Composite panels after 1,000-hr of immersion and then cured at 38°C (100°F) for 17 hr (left) and cured at 100°C (212°F) for 6 hr (right).

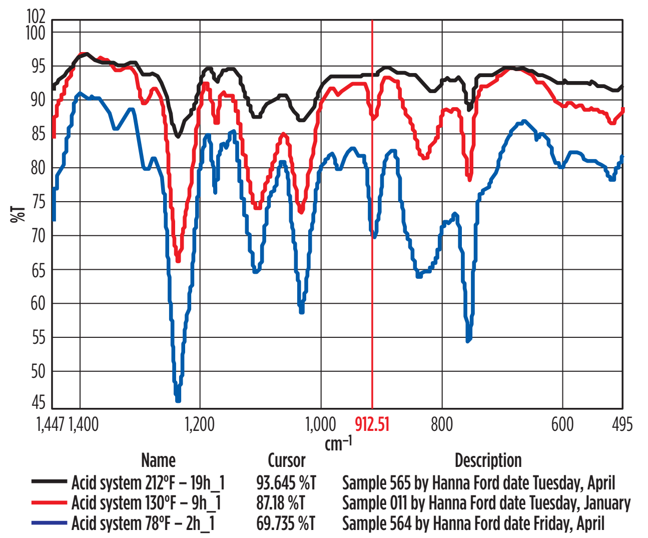

FIG. 6. FTIR spectroscopy of epoxy cured at different temperatures.

A view of the coupon sample before immersion and after 30 d is shown in **FIG. 3.**

For the composite panel test, panels cured at various temperatures and at different immersion times were also evaluated. This allowed for a review of the effect of cure temperature on both short- and long-term immersion conditions. Results for the different test panels and parameters are shown in **TABLE 5.** A view of the composite panel before immersion, after 30 d of immersion at a 38°C (100°F) cure temperature and after 30 d of immersion at a 24°C (75°F) cure temperature is shown in **FIG. 4.** A view of the composite panels after immersion for 1,000 hr, and then cured at 38°C (100°F) for 17 hr and cured for 6 hr at 100°C (212°F), is shown in **FIG. 5.**

The analysis of the change in appearance, weight, hardness and tensile properties reflected "excellent" chemical resistance between 98% sulfuric acid and the composite system when allowed to cure for 7 d at both temperature levels. To obtain the best properties in the system, this cure schedule may be completed. It was noted in the 1,000-hr test that the panel cured at the lower temperature, while performing to a "good" rating, did not perform as well as the panel cured at the higher temperature level, with regard to color retention (although mechanical properties were within the parameters of "excellent" rating), confirming that the level of cure of the epoxy polymer will still dictate the overall performance in long-term usage, and that the higher level of cure achieved, the better the system will perform. If the polymer system is fully cured, which is based on time and temperature, then it will meet the requirements, but may take longer to do so.

However, due to requirements of how the system would be used in a field environment, the recommended method would be to post-cure the system at temperatures between 38°C (100°F) and 134°C (273°F), which is the established T_g of the epoxy system to speed the full curing of the system to a more practical timeline. To characterize how this can be achieved with target temperatures and time, a study of the cure schedule at various temperatures was completed.

Determining the cure schedule options. Two methods for evaluating levels of cure were used to determine the required curing time and temperature of the composite system: Shore D hardness studies, and Fourier-transform infrared (FTIR) spectroscopy tests to measure percent of reduction in epoxy peak. The hardness of a composite system is a direct result of the resin matrix type and how well it is cured. The more rigid the resin, the higher the level of hardness achieved—whereas, the more flexible laminate will have a lower hardness level. Although hardness increases with degree of cure, this method is not enough to fully analyze the cross-linking reaction. For example, it is possible for an epoxy to appear solid, but to have not cross-linked to a degree that it will successfully resist the harsh chemical environment. Thus, the Shore D hardness study was complemented with the FTIR test to overlay the values and find the minimum recommended cure schedule for the ECRS.

In the FTIR results, the presence of the epoxy group on the infrared (IR) spectra is proven from the presence of a strong band at 912 cm^{-1}. Once the epoxy is fully cured, this peak should disappear, eliminating the area under the curve. It was demonstrated by the previous tests that, in these conditions, the system is chemically resistant to 98% sulfuric acid (**TABLE 5**). To ensure

TABLE 6. Cure study evaluations conducted at different temperatures

Cure temp = 24°C (75°F)			Cure temp = 38°C (100°F)			Cure temp = 55°C (130°F)		
Time, hr	Shore D hardness	Reduction of FTIR peak, %	Time, hr	Shore D hardness	Reduction of FTIR peak, %	Time, hr	Shore D hardness	Reduction of FTIR peak, %
1	7.4	0	1	11	0	1	13	2
3	24	–	3	29	18	3	36	22
5	39	15	4	50	21	5	69	53
7	48	–	6	62	27	6	73	55
16	55	–	8	67	36	7	75	56
24	61	22	10	67	41	8	76	62
29	65	–	12	72	45	**9**	**82**	**67**
30	68	30	13	76	46			
31	71	–	14	76	46			
48	80	–	15	76	47			
168	**85**	**57**	16	77	49			
			17	**78**	**56**			

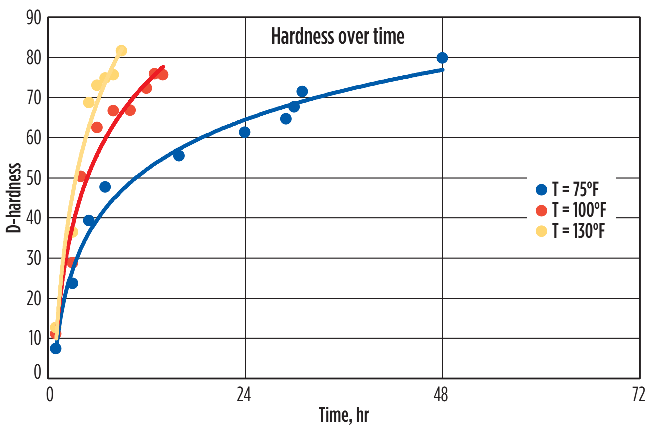

FIG. 7. Graph of hardness change over time.

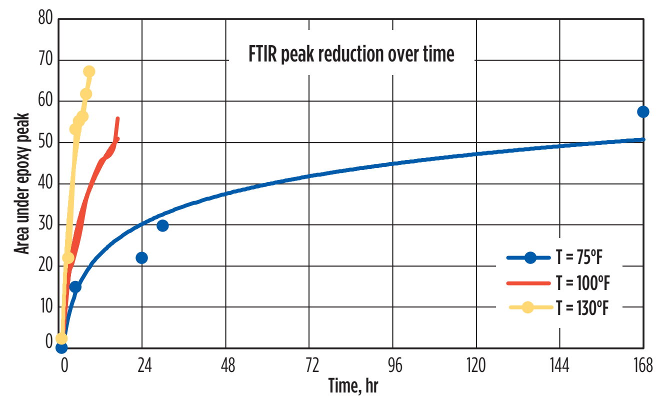

FIG. 8. Graph of FTIR peak reduction over time.

a fully cross-linked system (i.e., a fully cured system), the ultimate T_g must be reached, which is achieved by curing the epoxy at the measured T_g of 134°C (273°F). Note that successful usage may not require full cross-linking, but only a specific percentage. While this study is not fully vetted in this article, it should be considered for the practical application capacity of a system. This phenomenon can be seen in **FIG. 6,** where each line represents the FTIR spectroscopy of a different cure temperature. The top line represents a specimen cured at 100°C (212°F) for 19 hr, where there is no epoxy peak at 912cm^{-1} because the resin is fully cured. The red line has a small peak at 912cm^{-1}, which corresponds to a specimen partially cured at 55°C (130°F) for 9 hr. Finally, the blue line was cured at 24°C (75°F) for only 2 hr; the depth of the epoxy peak means that there is not yet a crosslinking reaction between the epoxy and amine, indicating that the sample is not fully cured. The area under the epoxy peak curve is what is considered for calculation purposes—the smaller it is, the more cured the sample is until it disappears, indicating a fully cured resin.

If this is not possible in the field of use conditions that this ECRS will be subjected to, then a minimum cure must be known. Since it was determined that chemical compatibility was successful at the previous time and temperature values, these were used as the baseline to plot expected cure curves for the system. **TABLE 6** displays the correlation of time with Shore D hardness values and percent reduction in FTIR peak values at three of the primarily reviewed temperatures. **FIGS. 7** and **8** show the change in hardness and the FTIR peak, respectively, over time. As can be seen within the figures, the previous statement regarding hardness being only one piece of the puzzle for cure measurement is shown to be true. Specifically, the samples cured at 24°C (75°F) reached their full hardness in 2 d or less, while the associated FTIR peak measurements took up to 7 d to reach the minimum levels to be considered to have a resistance to the 98% sulfuric acid.

Based on this information, it can be determined that specific curing protocols should be used for this system when it is going to be used with 98% sulfuric acid to ensure adequate resistance. The graphs can provide some ideas and indications of how to monitor and ensure that this cure level has been met when utilized in the field for repairs.

Qualifying the final ECRS. Upon completing the validation testing, and successfully characterizing the requirements and meeting the primary goals set forth, the last phase is to complete the full qualification testing to the ASME PCC-2 Article 4.1 and

TABLE 7. Full ASME and ISO standard qualifications testing summary

Property	Test methods	Results
Per ply thickness	Determined from the ASTM 3039 tensile tests	0.46 mm (0.018 in.)
Tensile strength (circumferential direction)	ISO 537-1, ISO 527-2 or ASTMD 3039	631.6 MPa (91.6 ksi)
Tensile modulus (circumferential direction)	ISO 527-1, ISO 527-2 or ASTMD 3039	37.7 GPa (5.5 Msi)
Tensile strain to failure (circumferential direction)	ISO 527-1, ISO 527-2 or ASTMD 3039	1.8%
Poisson's ratio (circumferential direction)	ISO 527-1, ISO 527-2 or ASTMD 3039	0.11
Tensile strength (axial direction)	ISO 527-1, ISO 527-2 or ASTMD 3039	158.6 MPa (23 ksi)
Tensile modulus (axial direction)	ISO 527-1, ISO 527-2 or ASTMD 3039	16.1 GPa (2.3 Msi)
Tensile strain to failure (axial direction)	ISO 527-1, ISO 527-2 or ASTMD 3039	1.52%
Shear modulus of polymer	ASTM D5379	0.96 GPa (139 ksi)
Shear strength of polymer	ASTM D5379	32.9 MPa (4.77 ksi)
Shore D hardness	ISO 868, ASTM D 2583 (ASTM D2240-04)	87
T_g of saturant	ASTM D6604	138°C (280°F)
Thermal expansion coefficient (circumferential direction)	ISO 11359-2, ASTM E831	7.1 ppm/°C (3.9 ppm/°F)
Thermal expansion coefficient (axial direction)	ISO 11359-2, ASTM E832	18.9 ppm/°C (10.5 ppm/°F)
Energy release rate	ASTM D1599	543 J/m2 (3.1 in.*lb/in.2)
Impact performance	ASTM G14 Modified, ASTM D1599	Passed
Short-term spool test	ASME-PCC 2	Passed for 314 bar (4,524 psi)
Lap shear strength (lap adhesion)	EN 1465, ASTM D3165 (ASTM D5868)	Short term: 7.98 MPa (1,158 psi)
Lap shear adhesion strength (1,000 hr of immersion in water)	ASTM D5868	Long-term 90°C (194°F) water: 5.23 MPa (759 psi)
Lap shear adhesion strength (1,000 hr of immersion in air)	ASTM D5868	Long-term 100°C (212°F) air: 7.47 MPa (1,083 psi)
Compressive modulus (filler)	ASTM D695	0.24 Msi

ISO 24817 standards for ECRSs. While this article will not go into the details of each test, the summary of all the completed qualification tests and achieved values are provided in **TABLE 7.**

Discussion. This article provides a detailed insight into the process and steps followed for the development of a system that is resistant to sulfuric acid in concentrations of 98% at ASTM conditions of 24°C (75°F). The main objective of this project was to create an ECRS that could be used as a valid and qualified pipe repair option for pipe systems operating with 98% sulfuric acid, which has been achieved. Numerous discoveries were made along the way—the most important of which was the effect of cure time and temperature on the resistance of the system to the chemical solution.

Upon full completion of the development and validation testing of the system, the full qualification testing was completed on the system. In addition, once completed with the initial validation, subsequent chemical compatibility testing programs were started to widen the scope of chemical solutions that could be used compatibly with this system—regarding both chemical compatibility and temperature ranges.

Takeaway. ECRSs are being utilized as a routine repair option for many process piping facilities, from refineries to fertilizer plants to steel mills. Because of the harsh conditions found in many of these facilities, advanced and thoroughly tested materials are required to be used successfully. Advancing technology requires commitment and persistence, as well as good cooperation between industry and the manufacturer. By fully characterizing and testing the composite materials across a spectrum of temperatures and other environmental conditions, users can be confident in the repair system's ability to successfully function as desired. The development of this new system is considered a breakthrough for its compatibility with sulfuric acid at 98% concentration, as it is the first composite repair system fully tested and proven to be resistant at such a level. HP

NOTES

This article was originally presented at the 2018 NACE Middle East Corrosion Conference

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Benefits of using a master station for actuator supervision and control in metering skids

Valve automation in metering skids for the oil and gas industry is a challenging task. High availability and easy integration of valves and actuators are crucial for these applications. Using a master station to control all of the actuators within the metering system has proven to have multiple benefits. This is illustrated by the use of a master station[a] for metering skids for a customer project.

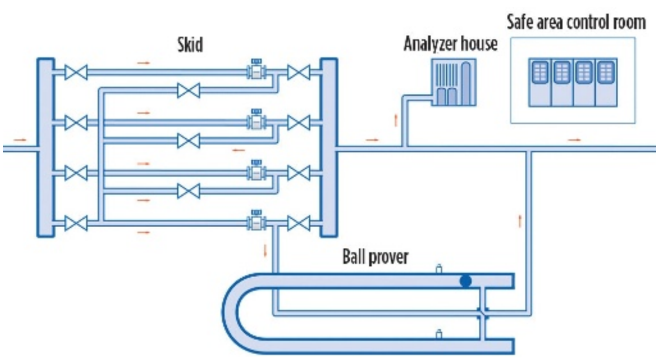

FIG. 1. The metering skids are turnkey, fully integrated metering systems for volume measurement of crude oil, natural gas and refinery products. Image courtesy of KROHNE.

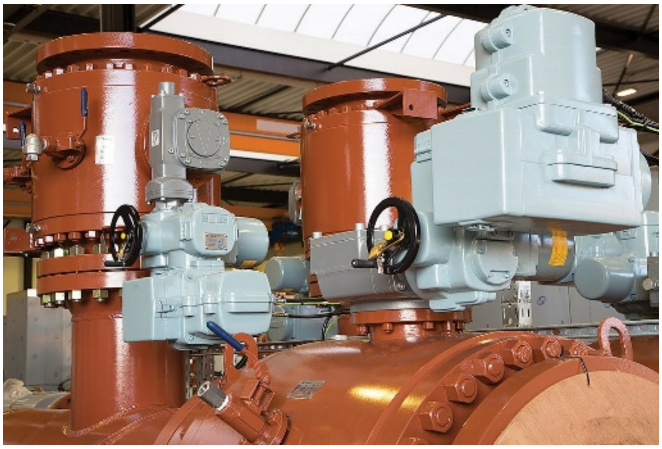

FIG. 2. To ensure that the valves can operate reliably even in the event of a fire, the actuators and actuator controls are equipped with fireproof shields. Image courtesy of KROHNE.

Metering skids are turnkey, fully integrated metering systems for highly precise volume measurement of crude oil, natural gas and refined products (**FIG. 1**). Typical applications include loading and unloading terminals for oil tankers, and measurements at the inlet and outlet of transport pipelines.

Actuators and valves, in addition to flowmeters and pressure and temperature sensors, are key components of such skids. For the most part, double-block-and-bleed valves are used since they are 100% leakage-free and so prevent measurement errors due to leaking valves. A skid normally has several

FIG. 3. Each metering skid has 12 actuators connected via a Modbus RTU loop with integral redundancy. Image courtesy of KROHNE.

Valve automation in metering skids for the oil and gas industry is challenging. Using a master station to control all of the actuators within the metering system has multiple benefits.

metering runs arranged in parallel, plus a master run for calibration. Actuators are needed for the flow control valves that direct the oil or gas flow to the individual metering runs and to the master run.

In one project, an automated metering solution for a major oil and gas group in the Middle East was implemented using a master station[a] that plays a key role in meeting the challenging requirements set by the customer. In many cases, the supplier of the actuators is dictated by the end user. However, in this case, different actuators were introduced as a cost-effective alternative in combination with the new, redundant master station[a].

Three metering skids were designed and manufactured, incorporating 36 actuators and one redundant master station[a] for high-accuracy measurement of crude oil. Each of the skids was equipped with three ultrasonic flowmeters. Within each skid, 12 actuators are used to control the flowrates and to switch between the different metering runs. They are connected to the master station in three separate loop topologies. The master station provides central control and monitoring of all 36 actuators across the three skids. To ensure that the valves can be operated reliably even in the event of a fire, the actuators and actuator controls are equipped with fireproof shields (**FIG. 2**).

High availability. Flow measurements from the metering skids are the basis for calculating the exact volume of oil or gas supplied and billed to the end customer. Any failure of the measurement system quickly results in high economic losses for the operator. High availability, therefore, was the customer's prime requirement for the metering skids; this extended to control and communication, as well as the reliability of the actuators themselves.

The master station is particularly beneficial here, thanks to its multiple redundancy options and its proven communication via standardized Modbus protocols. For this project, a master station with hot standby system redundancy was supplied. Two subsystems, cost-efficiently located within a single housing, ensure that operation continues without interruption, even if one subsystem fails (**FIG. 3**).

Communication to the distributed control system (DCS) is also redundant, via Modbus TCP/IP (internet protocol suite). The actuators are connected to the master station via Modbus RTU (remote terminal unit) in a loop topology. Redundancy is also included at this level: if communication fails at a specific position within the loop, then the master station considers both the resulting segments as individual lines and all actuators remain accessible. Additionally, communication via Modbus is extremely fast and efficient, resulting in short cycle and reaction times.

The metering skids, including the valves and actuators, were fully assembled and tested at the manufacturing plant in the Netherlands (**FIG. 4**). For transport to the end user, only the external connections were separated, thereby minimizing the steps needed to install and commission the pre-assembled modules at the customer's site.

Using a master station as a central control hub for all of the actuators considerably reduces the external connections need-

FIG. 4. The metering skids were fully built and tested at the manufacturer's plant in the Netherlands, including the valves, the actuators and the master station. Image courtesy of KROHNE.

ed at the actuator level. Only two fieldbus cables are needed per skid to connect the actuators' Modbus loop to the master station. At the customer site, only the master station then needs to be connected to the DCS.

Benefits during commissioning. Commissioning of the actuators took place in the skids manufacturer's factory using the master station, without requiring a connection to a DCS. The master station's large, integral, multi-touch screen allowed the actuators to be intuitively controlled and tested,

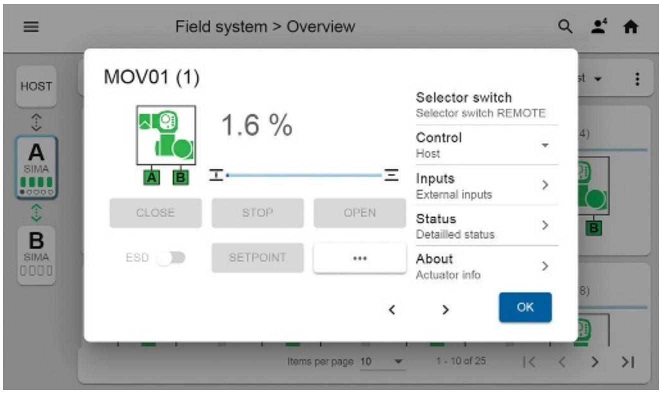

FIG. 5. The master station operation is intuitive and convenient with either the integral, multi-touch screen or an external web browser. Image courtesy of AUMA.

and the communication parameters set (**FIG. 5**). The actuator networks for each of the three metering skids also could be preconfigured using the master station. Commissioning was accomplished with the master station's automatic loop configuration feature, which facilitates actuator address assignment within the network.

Central diagnostic hub. During normal plant operation, the use of a master station reduces host communication to a minimum, thereby reducing the workload on the DCS. The master station distributes the individual operation commands to each actuator, receives status updates from all of the actuators at cyclic intervals, and transmits to the DCS only the concentrated data required for regular plant operation. In addition, the master station offers a multitude of diagnostic functions. Status and availability are clearly visible at all levels, from the overall system down to each individual actuator. This speeds up fault localization and repair (**FIG. 6**).

Additional customer requirements that evolved during the course of the project were quickly accommodated. For example, a new software feature to enable additional configurable feedback signals was implemented. This feature is used to monitor the external 24-V power supply to the actuators. The master station also incorporates integral Ethernet interfaces, opening new possibilities for enhanced data exchange, including Industrial Internet of Things (IIoT) applications.

Takeaway. The master station has provided added value for metering skids due to easy commissioning, centralized control of all actuators, and a multitude of diagnostic functions. Efficient, high-speed Modbus communication and integral redundancy at all levels ensure reliable plant operation and optimized processes. HP

NOTES

[a] AUMA's SIMA^2 master station, used for metering skids built by KROHNE Oil & Gas

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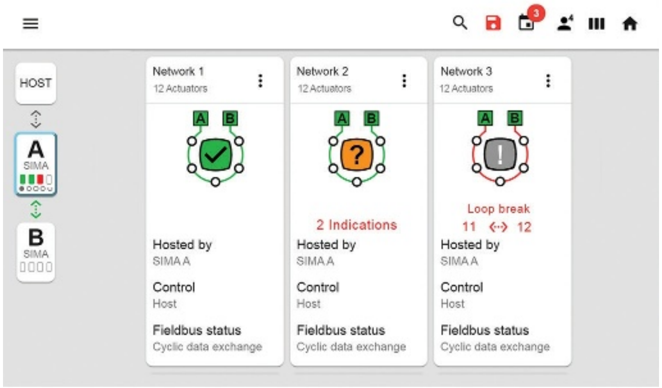

FIG. 6. Acting as a central diagnostic hub, the master station facilitates fault detection at all levels, from the overall system down to the individual actuator. Detailed configuration and status information facilitates diagnostics and accelerates troubleshooting. Image courtesy of AUMA.

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Avoid costly stockouts through inventory sharing

Inventory sharing, per se, is not a new concept; rather, it is a popular practice in the wholesale and distribution business. However, the collaborative arrangement of inventory sharing among manufacturing industries is a new concept and not widespread. The author was involved in a successful inventory sharing project among neighboring industries, and this article details how it can be accomplished with minimal time and effort.

Inventory sharing among group companies located in multiple geographical locations or among neighboring industries can prevent costly stockouts, improve uptime, reduce emergency purchases, prevent obsolescence and dispose of surplus inventory—truly a synergistic, win-win situation for all collaborating companies. Contrary to the common apprehension of how inventory can be shared when participating companies have different enterprise resource planning (ERP) systems, end products, manufacturing processes, technologies, etc., it is simple and once operational, requires very little or zero maintenance.

Manufacturing industries must stock various classes of spares, such as operational spare parts and generic items like pipes and pipe fittings, electrical fixtures, fuses, cables, valves, conveyor components, lubes, etc. Since line managers want to avoid stockouts at any cost, they tend to stockpile inventory; over time, 8%–10% of these get damaged, become obsolete or remain unused. Despite stocking so much inventory, costly stockouts are not uncommon. In the event of a stockout crisis, line managers and the purchasing department often struggle to acquire the required part in the least possible time to minimize the plant outage. Consider that a neighboring company may have the required spare or component and could easily share or loan it, avoiding a long unit shutdown.

Inventory is capital idling in storage and is considered a sunk cost. Despite a continuous management focus on inventory control, the inventory value keeps mounting year-on-year. Many continuous process industries are situated in industrial zones and are close to each other. Many large companies have units in more than one geographical location, often manufacturing the same product. Some equipment or machinery are common across industry, even if the product is different (e.g., a gas turbine for a captive power plant, a diesel engine set for emergency power, air compressors for plant and instrument air, fire water systems, belt conveyors).

Among generic items (valves, pipes and pipe fittings, fasteners, fuses, cables, etc.), the degree of interchangeability among industries is significant. Most urea/ammonia plants in India utilize the same technologies and have almost the same nameplate capacities for each train. For critical equipment, industry tends to focus on only one or two preferred manufacturers. However, it is advantageous in most stockout cases to consider and use substitutes.

Inventory sharing can help optimize inventory and keep critical and insurance spares at one location rather than all locations or factories stocking the same interchangeable insurance spares. By their very nature, insurance spares may not be required during the entire lifetime of equipment, yet companies must keep them—in the unfortunate event of equipment damage or failure, securing the needed insurance spare may take several months, and stockouts can drive the company out of business.

Avoiding missteps. During an inventory sharing project in Qatar in which the author participated, team members from the participating companies met weekly to decide the modalities of the project. The team realized that differences existed in the way the item master was being maintained by the companies:

- Companies were using different ERP systems
- Different levels of maturity existed in the upkeep of the item master
- There were discrepancies in units of measurement when specifying sizes (e.g., in. vs. mm)
- Some companies used ASTM designations for materials while others used BS or other standards.

The team consensus was to devise a common codification logic and instate a uniform way of describing the items. This

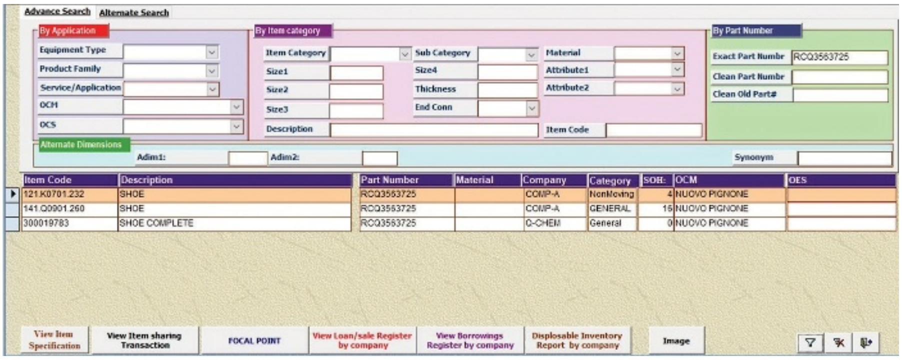

FIG. 1. Inventory sharing application developed by the author.

information was then fed into a new material cataloging software to identify the commonality of spares among the companies. Drawing up the common specification for the new codification system and codifying the existing inventory took several months—the enormous time, money and resources required to recodify all stock-keeping units (SKUs) in a unified way was a big stumbling block. It also required the companies to switch to the new unified system after going live. This caused resistance from line managers as everyone had to shift from existing material code to new code, which entailed updating the item code at several places (bill of materials, purchase orders, material tagging in warehouses, etc.)

Moreover, the sizes of the participating companies varied greatly: the number of SKUs ranged from 15,000 to more than 100,000 in large companies. The idea that the project's cost should be shared equally was vehemently opposed by smaller companies, which began questioning their participation. After almost a year of weekly meetings, the project was shelved due to failure in finding a workable solution.

In another case, a large company with multiple units in its home country and overseas had a common ERP system across the group. The company wanted all units to participate in inventory sharing. Because all units shared the ERP system, it was assumed that the only hindrance to identifying the interchangeable parts across the units was different codification systems. The task of implementing uniform material codes across all sites required significant effort. The individual units worked for several months to assign new codes and feed them into the ERP. However, the result was unsuccessful, and no inventory sharing took place.

New approach revives project. These examples of failures highlight the common misconception among many continuous process industry professionals and decision makers—even in this age of computerization and e-commerce—that common material cataloging is needed to identify the interchangeability among various units or factories.

Inventory sharing among manufacturing industries and group companies can prevent costly outages, dispose of surplus and obsolete inventory, and clean up the inventory by identifying and eliminating duplicate SKUs within the warehouse.

It can be assumed that no two companies have the same ERP system. It can also be accepted that some companies may be properly maintaining the item master with complete specification, make, model, size, material of construction, manufacturer part number, etc., of the component or equipment where the component is fitted, while other companies will not have complete specification for the items. A difference exists in the number of SKUs held by companies of various sizes, as well.

The basic requirement of inventory sharing is that companies can continue to operate their day-to-day business using their existing ERP and style of codification, yet be able to quickly (in case of a stock out) access the inventory of a neighboring company, find the required exact match or substitute, and borrow or buy it.

In a second attempt, it was decided to pursue an aggregator software that would collect the item master dump (in the prescribed format) daily from the ERP systems of participating companies, and to update the same in a common aggregator software with a superior search facility. Proper data mapping was done for individual ERP systems in the aggregator software so that respective fields were populated from flat files received from various ERP systems as a part of the implementation scope.

Not only were the required efforts reduced, but the costs were also much lower than the earlier model. The companies agreed to participate and equally share the initial and yearly maintenance costs, and the project was successfully commissioned in less than 4 mos after floating the request for quotation (RFQ).

The process of extracting the item master dump from various ERP systems and updating the same in the aggregator software was automated. Initially, some companies shared only the item master details of surplus and non-moving items while withholding the sharing of SKUs that were in regular use (general category). Also, many companies did not share the unit rate information. However, seeing the versatility of inventory sharing in searching the required inventory, identifying the duplicates, generating inventory reports such as inventory value, etc., the companies later began sharing the entire material master, including pricing information. Based on the feedback and the frequency of lending and borrowing among companies of costly spares and generic items, the project was a success.

How to get started? Once the merits of inventory sharing have been proven, the unit head of the most influential large company will normally take the lead during interactions with counterparts in other companies. Once buy-in is achieved, a point person (usually a maintenance or planning manager) is nominated from each company and the team leader is selected from among that group. The team should meet weekly to carry out the following steps:

1. Hold a kick-off meeting and share contact details.
2. Collect data on the number of SKUs and ERP systems of all participating companies.
3. Review the method of maintaining the item master and completeness of basic data.
4. Decide which fields are to be shared—the minimum information required are item code, item short and long description, manufacturer, model number, manufacturer part number, unit of measure, stock on hand, surplus or disposable stock, size, rating, material of construction, unit rate, date of last purchase/receipt, item location, etc.
5. Decide on optional fields to be shared, such as unit price, supplier name, purchase order price, etc.
6. Prepare an RFQ for inventory sharing aggregator software

solution providers, including a provision to view the test certificates, photographs of the component, etc. Send requests through the software to all team leads. There should be various ways to narrow down the search (e.g., by make, model, size, rating, end connections, manufacturer's part number, supplier part number) and to search by synonyms, and accept wild cards and keywords. Also, it should be able to look for alternate dimensions (e.g., if inches are specified, it should also locate equivalent sizes, such as mm).

7. Arrange for a technical presentation by the vendors that have submitted their quotations.
8. Negotiate and place the order to the selected vendor and decide on the cost-sharing formula for software and annual licensing fees.
9. Customize and upload the item master dump and provide training to team leads.
10. Go live and allow team leads to train other users of the ERP.

The exercise can be completed in 3 mos–4 mos and the payback can be less than 1 yr. The author has developed an application for inventory sharing (**FIG. 1**) that can—in addition to the usual search criteria available in the aggregator software—locate the item even if it is misspelled. It can look for alternate dimensional standards (in. vs. mm, hp vs. kW, etc.), display photographs of the item selected, view detailed specifications and test certificates, and more.

As an example, suppose company "Q-chem" is in urgent need of a bearing shoe for its compressor and searches for the part by entering the part number in the software, as illustrated in **FIG. 1.** The search has produced three SKUs, one held by Q-chem and two held by Company A. There are duplicate SKUs in Company A: one SKU is declared as non-moving and stock is available for disposal; whereas the second SKU of Company A shows a "general," meaning it is in use and required to be stocked and replenished. Thus, companies can also identify multiple codes and merge the duplicate stocks. In this example, Q-chem would send a request to Company A to sell the non-moving SKU to them after verifying that the spare part is properly preserved by Company A by viewing the photo of the component. Company A will readily sell the item as it is non-moving with them. This is a win-win situation for both organizations. HP

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Implement effective operational discipline programs to improve process safety performance—Part 1

Operational discipline (OD) describes human behavior in complying with required systems, every time, to consistently achieve organizational goals and overall operational excellence.[1,2] While a focus on OD is not a panacea, OD is a fundamental part of effective programs for achieving excellent performance in process safety, environmental, health and safety programs, quality, reliability and productivity.[2,3,4] Well-designed management systems are only the first step; the disciplined efforts of involved personnel in effectively implementing and following system requirements continuously are also needed. Failing to follow a system requirement—even just once—due to a human performance issue, inattention, complacency or other reason, can result in significant consequences, such as personal injury, environmental harm and business loss.

For example, an incident investigation by the U.S. Chemical Safety Board (CSB)[5] concluded that an operator opened the bottom valve of an operating polymerization reactor, apparently bypassing an active pressure interlock, instead of the intended action of opening the bottom valve of a nearby reactor that was being cleaned. The resulting large release of hot, flammable material from the operating reactor ignited, leading to five fatalities and major damage to the facility. While the U.S. CSB investigation identified several other design and operating issues, human errors like this must be anticipated and appropriate safeguards provided to help prevent serious injuries and other significant consequences. Focusing on OD—doing the right thing, every time—is an essential component of maintaining effective safety programs and achieving excellent safety performance. Steps for getting started in implementing an OD program, or improving an existing effort, are discussed here.

Precursors to implementing OD. Precursors to implementing OD programs include:

- Recognizing and assessing hazards
- Implementing risk management programs.

It is necessary to know what hazards may be present to develop appropriate risk management requirements, so initial and continuing efforts to identify and assess hazards in the workplace define the type and level of risk management program needed.[2,6] If the hazards are not identified and assessed properly, how can appropriate safeguards and systems be implemented and maintained to manage the risks associated with those hazards? If process hazards, such as toxicity or flammability, are present, then a process safety program is needed. Depending on the actual level of risk, the quantity of hazardous materials present, intrinsic hazards, processing conditions, reactions and other factors, the requirements of a process safety program may vary and may or may not require regulatory compliance, such as with the Occupational Safety and Health Administration's (OSHA's) process safety management standard or other regulations. Occupational safety, industrial hygiene, environmental protection and other programs may also be required to help ensure all hazards are appropriately identified and managed.

As shown in **FIG. 1,** effective safety programs consist of three interrelated foundations[2] comprising:

1. **Safety culture and leadership—** Safety culture and leadership help define how an organization approaches and prioritizes problems and issues related to managing safety.[2,7] Is safety a core value with high priority in all cases, or is it more of an afterthought, subject to potentially conflicting organizational priorities such as cost or productivity? Safety culture influences the daily behaviors of leadership and workers, who either reinforce and improve the culture over time or allow it to degrade. Safety culture and leadership are part of the overall organizational culture that encompasses all the ways work is or should be done, as well as how it is impacted by safety considerations and requirements. In a weak safety culture, or with unaligned leadership, implementation of effective safety programs is often constrained, and achievement of excellent safety performance is difficult.

FIG. 1. Foundations of an effective safety program.[2]

2. **Safety systems**—Comprehensive management systems provide a framework to help ensure hazards and associated risks are identified, evaluated and controlled.[2,7] In many cases, regulatory requirements provide a good starting point for defining the needed systems and requirements; however, in all cases, proper evaluation of potential risks is required to help ensure they are controlled and managed appropriately. This may necessitate going beyond the minimum essential practice defined by regulations, or may lead to complying with regulatory requirements when not required. Regulations [e.g., OSHA, U.S. Environmental Protection Agency (EPA)], consensus industry standards [e.g., National Fire Protection Association (NFPA), American Petroleum Institute (API)], industry guidance [e.g., Center for Chemical Process Safety (CCPS), American Society for Safety Professionals (ASSP)] and extensive literature provide detailed guidance for implementing appropriate safety management systems.
3. **Operational discipline**—OD, as defined previously, relates to how well safety and other systems are followed.[2,8,9,10] OD is influenced by many factors, including safety culture and leadership, quality of safety systems, and other human behavior and human factors programs.

Some precursors related to safety culture, leadership and safety systems that impact the effectiveness of an OD effort are listed below. Consideration should be given to implementing or strengthening safety and related programs in these areas if they are deficient.

Some precursors to effective OD programs include:

- Establishing safety as a core value vs. potential conflicting priorities, such as cost or productivity
- Committing to consistent and visible leadership of safety
- Promoting a sense of vulnerability to support safety awareness and engagement and avoid complacency
- Maintaining open communications
- Documenting operating procedures and safe work practices
- Developing effective and timely training practices
- Implementing fitness-for-duty programs to mitigate possible worker impairment due to stress, fatigue, alcohol, prescribed or over-the-counter medications, or illegal drugs
- Evaluating and managing process risks
- Monitoring and reviewing key performance indicators
- Providing management of change (MOC) programs to identify and manage new hazards that may be introduced
- Implementing equipment inspection, testing and preventive maintenance programs to help ensure tools and equipment are reliable and safe to use.

OD program characteristics. The characteristics and importance of effective OD programs have been discussed elsewhere[2,11,12,13] and have recently been reviewed in the context of achieving excellent process safety performance,[3,4] reducing loss of containment incidents[14] and as a leading indicator of plant performance.[15] OD programs comprise both organizational and personal OD efforts. The characteristics describing organizational OD[2,11] are intended to help company and/or facility leadership develop effective OD programs, based on:

- **Leadership focus:** Leaders emphasize and provide a positive work environment, managing processes and resources for effective programs and employee engagement. Leaders are personally involved and passionate about safety and reflect the behaviors they expect from their organization. A leader's consistent behavior helps build trust and engagement in the organization.
- **Employee engagement:** Employees understand and value the importance of safe work activities and contribute to organizational programs and activities.
- **Procedural principles:** Correct ways of performing work are defined and completed as planned, following documented and authorized systems and procedures.
- **Housekeeping and workplace standards:** Standards are established for maintaining safe equipment, tools and facilities. Employees are proud of their work environment and consistently maintain high levels of housekeeping.

Organizational OD efforts are closely related to good safety culture and leadership practices. As shown in FIG. 1, effective safety management systems also help enable workers at all levels of an organization to do their work correctly and safely, every time.

The characteristics describing personal OD[2,11], as shown in FIG. 2, are intended to support the day-to-day focus on OD to help ensure all employees:

- Know how to perform their work correctly and safely (**knowledge**)
- Commit and plan to perform the work the correct way without deviations or shortcuts, based on training (**commitment**)
- Anticipate and are prepared for what could go wrong or look for and recognize what may be different in their current work environment and respond accordingly, based on training and experience (**awareness**).

The goal is to have knowledgeable, prepared, experienced workers at all levels of the organization who account for the existing work environment rather than have an unquestioning focus on strict adherence to procedure when circumstances vary or change. This requires developing appropriate operating procedures and effective on-the-job training for required work activities, including recognition and troubleshooting of possible deviations and the

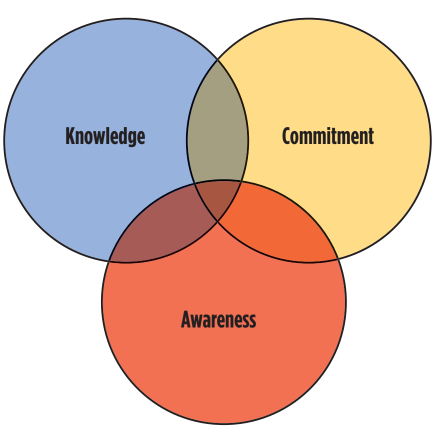

FIG. 2. Characteristics of personal OD.[2,11]

correct responses. This provides a foundation for thoughtful compliance. A summary of the OD program characteristics and their relationships is shown in FIG. 3.

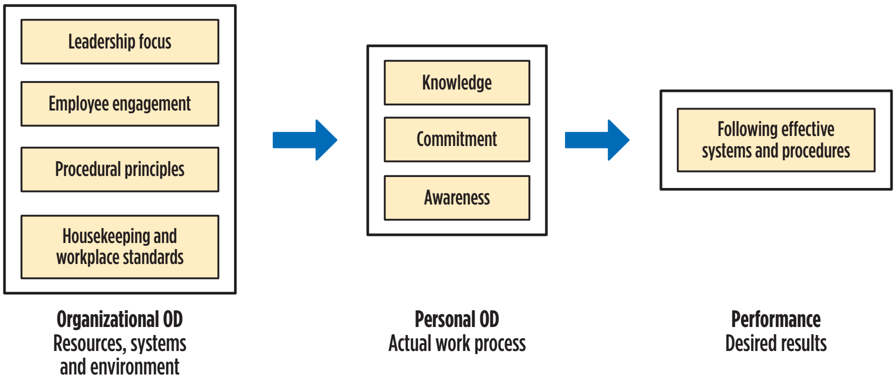

FIG. 3. Relationship of OD program characteristics.[2]

IMPLEMENTING EFFECTIVE OD PROGRAMS

Implementing an effective OD program or improving an existing program depends on the starting point and intended goals. Key activities, which will be discussed in following sections, include:

1. Focusing on OD improvement
2. Raising awareness and value for OD
3. Evaluating OD performance
4. Identifying, prioritizing and pursuing improvement opportunities
5. Sustaining and renewing OD program activities.

Focusing on OD improvement. Management should consider improving OD for the following reasons:

- A required part of effective safety programs, as shown in FIG. 1
- Poor performance either creates the desire to improve or allows continued problems
- Good performance creates the desire to avoid complacency.

Benefits of an effective OD program include:[2,8]

- Process (and other) hazards and risks are identified, evaluated and managed
- Equipment and facilities are properly designed, operated and maintained
- Management systems are well designed, implemented, executed and supported
- Operating problems, incidents and near misses are consistently investigated and addressed.

As a result, process safety, environment, health and safety (EHS) performance, productivity and cost, and product quality performance should improve. To achieve or improve these results, appropriate management focus on improving OD is required to get started due to the need to:[2]

- Demonstrate personal attention and commitment to the effort
- Provide appropriate resources to support program execution
- Develop effective processes to facilitate employee awareness, understanding and involvement
- Implement, improve, standardize and maintain needed systems and activities
- Support, evaluate and monitor performance, including frequent observation of work tasks.

OD-related requirements should be added to appropriate process safety, incident investigation, auditing, and other standards and guidelines to support consistent implementation of OD activities. For example, incident and near-miss investigation standards should be revised to include the identification of OD-related causal factors, which can be used to help reduce incident frequency and identify potential OD improvement opportunities. OD learning opportunities can be also identified from investigating EHS, quality, productivity and other operational problems, in addition to process safety.

Failure to implement or sustain effective OD programs can be catastrophic. For example, the 2005 Texas City refinery explosion investigated by the U.S. CSB[16] resulted in 15 fatalities, 180 injuries and major facility damage, as shown in FIG. 4. While the CSB identified many causes, some of the OD issues identified in the CSB investigation of the incident are highlighted below. Subsequent investigations[17] of several company refineries found "instances of a lack of OD, tolerance of serious deviations from safe operating practices, and apparent complacency toward serious process safety risks at each refinery."

FIG. 4. The aftermath of the 2005 Texas City refinery explosion and fire.[16]

Examples of OD issues identified by the CSB refinery investigation include:[16]

- Management did not emphasize the importance of following procedures as evidenced by its (1) lack of enforcement of the MOC policy, (2) acceptance of procedural deviations during past startups, and (3) failure to ensure that procedures remained up to date and accurate, contributing to a work environment that encouraged operations personnel to deviate from procedures.
- Inadequate training for operations personnel contributed to causing the incident. The hazards of unit startup and for abnormal situations were not adequately covered in operator training.
- A "check-the-box" mentality was prevalent, where personnel completed paperwork and checked off on safety policy and procedural requirements even when those requirements had not been met, contributing to a culture of "casual compliance."
- Managers did not effectively implement their pre-startup safety review policy to (1) ensure nonessential personnel were removed from areas in and around process units during startups, and (2) verify the adequacy of all safety systems and equipment,

- including procedures and training, process safety information, alarms and equipment functionality, and instrument testing and calibration.
- A lack of supervisory oversight and technically trained personnel during the startup, an especially hazardous period, was an omission contrary to refinery guidelines. No experienced supervisor or technical expert was assigned to the startup after the day supervisor left, although safety procedures required such oversight.
- An effective incident investigation management system to capture appropriate lessons learned and implement needed changes had not been employed.
- The mechanical integrity program did not ensure that deficiencies were identified and repaired prior to failure, resulting in the "run to failure" of process equipment.

An effective OD program emphasizes completing all tasks correctly and safely, every time, regardless of the role of individuals in the organization—it is important to recognize that OD is for everyone, not just operators. Kletz,[18] for example, observed that:

> Every accident is due to human error: someone, usually a manager, has to decide what to do; someone, usually a designer, has to decide how to do it; someone, usually an operator, has to do it. All of them can make errors, but the operator is at the end of the chain and often gets all the blame. We should consider the people who have opportunities to prevent accidents by changing objectives and methods, as well as those who actually carry out operations.[18]

It is also important to recognize that OD improvement efforts must relate to specific local site or organizational issues, based on differing safety culture, leadership, work activities, hazards and/or geographic locations. These factors likely vary from one site or area to another, especially in larger companies or facilities. Common issues may be identified, but local differences may lead to different priorities for improvement. Frequent observation of specific work activities can assist in identifying potential OD improvements.

It is necessary to start where you are, recognize where you are going and determine where you actually want to go in terms of improving OD. The FLAME model[2] describes best practices for leadership efforts in getting started on improving OD:

- **Focus:** Develop a plan to provide and enable appropriate focus on OD and effectively communicate the plan and associated goals to develop awareness and engage site personnel, who are supported daily through leadership attention and priorities.
- **Leadership:** Leadership acts as visible role models, committed to continuous improvement and excellent OD performance through the use of effective, consistent leadership practices.
- **Accountability:** Organizational, team and individual goals include a focus on OD with clear expectations on performance, feedback and recognition, as appropriate.
- **Measurement:** Metrics, audits and other tools are defined to periodically assess site activities, performance and progress toward goals.
- **Engagement:** Leaders provide a work environment that provides engagement and support to site personnel, based on good communication processes, employee input and involvement, and interdependent behaviors. Site personnel know they are important to success and their contributions are valued.

Although OD improvement is ultimately the responsibility of everyone in an organization, it can be helpful to assign an OD champion and team to provide additional focus and accountability for implementing and sustaining effective OD programs. An important goal is to create an OD flywheel[19,20] or habit[21], where initially small changes lead to larger improvements and momentum over time to achieve OD goals and improve performance.

Part 2, which will appear in the March issue, will discuss raising OD awareness, evaluating OD performance, pursuing improvement opportunities and sustaining OD programs. HP

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Automating valve actuators

Cowan Dynamics has made advancements to its "C-PAC Module" Pneumatic Manifold and launched the C-PAC store. The C-PAC (Cowan's Pneumatic Actuator Control) is an out-of-the-box solution and can save up to 90% in assembly time and easily automate valve actuators without using cumbersome and costly piping to connect various automation components. The C-PAC Pneumatic Manifold has the following capabilities for linear and 1/4 actuators: speed control, safety pressure relief and fail-safe capabilities.

The C-PAC Pneumatic Manifold's preassembled manifold configuration eliminates potential leak points and time-consuming troubleshooting that normally would occur with conventional manual installations. Quality improvements such as ASCO solenoid valves are now standard, replacing the option for generic brands.

The C-PAC is also available without pre-installed ASCO solenoid valves. Actuator technicians have the flexibility to select any solenoid valve brand with the appropriate area classification, ensuring complete compatibility. The online store gives valve automation centers and technicians the ability to easily configure the C-PAC module with more than 35 variations for their application. The C-PAC pneumatic manifold can be ordered in three sizes: ¼-in. NPT, ½-in. NPT and 1-in. NPT.

Monitoring solution for gaseous fire suppression systems

Kidde Fire Systems has launched its new IntelliSite™ remote monitoring system for gaseous fire suppression systems. The IntelliSite system allows users to monitor the status of a portfolio of fire control units in real time across multiple locations. With 24/7 information access, the IntelliSite system (FIG. 1) enhances safety and service levels for system end-users and can help reduce service calls, maintenance and administration costs.

The system allows users to monitor Kidde Fire Systems addressable fire-suppression control units via computer, tablet or smartphone. Using secure cellular connectivity, control unit status along with the status of all associated detection devices and supervised suppression systems are at the user's fingertips, providing information-based decision-making.

Benefits to distribution channel partners and end users include:

- Offers valuable insights with real-time event information
- Significantly reduces service times with remote system analysis and maintenance planning
- Increases service levels and customer satisfaction with 24/7 remote access
- Reduces operational expenses and unbillable service calls by optimizing field service technicians' time
- Keeps users informed of system status with automated notifications.

The IntelliSite system is compatible with Kidde Fire Systems addressable control units as well as legacy Chemetron® and Fenwal® control units. The IntelliSite mobile app is compatible with iOS™ 11 and later, and Android™ 6 and later operating systems.

Digitalizing process safety lifecycle management

ABB has launched ABB Ability™ SafetyInsight™, a suite of digital software applications that supports companies across the energy and process sectors throughout the entire lifecycle of process safety management (PSM). Operating as a central source of information, the software digitalizes early engineering technology (ET) data to create a process safety digital twin, giving context to the vast amount of data generated through information technology (IT) and operational technology (OT) systems.

By combining IT and OT data with ET data, SafetyInsight enables valuable engineering data (such as HAZOP and LOPA reports) to be digitalized, and readily accessible by operation and maintenance teams (FIG. 2) in simplified, intuitive and easy-to-understand visual formats.

Ongoing risk assessments can then be based on digitalized safety data. The addition of the IT/OT data provides near real-time updates, enabling the accumulative impact of operation and maintenance activities to be visualized on a dynamic risk matrix, to further aid risk assessments and management of operational risk.

The suite delivers process safety dashboards to provide the right information,

FIG. 1. Kidde Fire Systems' new IntelliSite™ remote monitoring system for gaseous fire suppression systems.

FIG. 2. ABB has launched ABB Ability™ SafetyInsight™, a suite of digital software applications.

to the right person, at the right time, to make the right, informed decision, according to ABB.

Managing, connecting and optimizing heat trace systems

Thermon Group Holdings Inc. has presented the Genesis™ Network, a new solution providing site-wide operational awareness and supervisory control of heat trace systems. With the Thermon Genesis Network (FIG. 3), users save maintenance hours, increase up-time, and make upgrades and changes with greater flexibility. Users can easily monitor, maintain and troubleshoot even the largest heat trace systems that may include more than 10,000 heat trace circuits. The Genesis Network connects heat trace controllers with the control room using wireless communications. The solution presents alarms, history and operational data via a user-friendly, browser-based interface accessible from any network-connected computer or mobile tablet. Utilizing an adaptive, self-healing wireless mesh network and event-driven communications, users experience reliable, real-time status reporting and responsive control of their heat trace systems.

FIG. 3. The Thermon Genesis™ Network provides site-wide operational awareness and supervisory control of heat trace systems.

FIG. 4. FLIR Systems Inc. has made four new additions to its Exx-Series of advanced thermal imaging cameras.

The following new components work together to form a Genesis Network: Genesis Server, an on-premises or cloud deployable server; Genesis Gateway, a communications device between the server and wireless mesh; and Genesis Bridge, a communications device between the mesh and heat trace controllers.

Maintenance personnel need timely and complete awareness of the trace heating system to prevent downtime and optimize operations. They also require information to troubleshoot issues quickly and accurately. The Genesis Network answers these challenges by delivering alarm management, setting optimization, historical analysis and operational reporting. The solution can save significant time through the use of historical data to optimize settings and accurately flag outlier behaviors while avoiding nuisance alarms, resulting in fewer maintenance hours. The Genesis Network also saves time by filtering and prioritizing alarms and generating reports with the right information to make efficient decisions.

The Genesis Network is architected as a true Industrial Internet of Things (IIoT) solution. An intuitive browser-based user interface gives users quick access for performing alarm management, report generation, data trending and performance optimization of heat trace circuits while on-the-go from any network-connected laptop or mobile tablet with a browser. Adding or changing devices is a simple drag-and-drop activity. Software updates to the network can also be deployed to all devices via the browser interface, making the roll out of new features simple, increasing the value of the solution over time.

Designed with security in mind, from data encryption and authentication to secure updates, operational leaders can deploy the Genesis Network with peace of mind. In applications where wireless communications are prohibited, the network can be configured using a traditional wired solution.

Handheld thermal imaging cameras

FLIR Systems Inc. has made four new additions to its Exx-Series of advanced thermal imaging cameras (FIG. 4): the E96, E86, E76 and E54. Compared to predecessor Exx-Series cameras, the new cameras offer enhanced thermal resolution for more vibrant, easy-to-read images and on-camera routing capability to improve field survey efficiency. The new Exx-Series cameras are designed to help professionals detect the early signs of building issues, identify hot spots, troubleshoot electrical and mechanical systems, and prevent problems before they cause damage that leads to expensive repairs.

The E96, with a 640 × 480 resolution and eight-times digital zoom, is the most advanced Exx-Series thermal camera to date. It delivers improved measurement results over the greatest distance to target, so professionals can safely diagnose electrical faults or locate hidden anomalies at very high temperatures up to 1,500°C (2,732°F), including in harsh industrial environments.

For the first time, FLIR Inspection Route is now offered as a standard feature on every Exx-Series camera and is complemented by the FLIR Thermal Studio Pro software with Route Creator plugin, sold separately as an annual subscription. The complete routing bundle enables professionals to create and export custom inspection and pre-planned routes, ideal for large or multi-location electrical or mechanical projects.

The E96, E86 and E76 include UltraMax® high-definition image enhancement technology and improved contrast with one-touch level and spanning functions to view greater image details. In addition, interchangeable AutoCal™ lenses offer complete coverage of near and distance targets, with the built-in laser distance meter ensuring the crisp focus needed for accurate temperature measurement. HP

An expanded version of Innovations can be found online at HydrocarbonProcessing.com.

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HP Events

FEBRUARY

ARC Industry Forum,
Feb. 8–11, Virtual event
www.arcweb.com

Future Downstream Automation Summit, Feb. 18, Hyatt Regency Intercontinental Hotel, Houston, Texas
P: +44 0-113-2647-914
info@amg-world.co.uk
www.futuredownstream.com

Asia Turbomachinery & Pump Symposium (ATPS), Feb. 23–25, Virtual event
P: +1 979-845-7417
info@turbo-lab.tamu.edu
atps.tamu.ed

MARCH

CERAWeek, March 1–5,
Virtual event
www.ceraweek.com

Asian Refining Summit,
March 4, Virtual event
P: +65 65-30-6430
plattsinfo.spglobal.com

35th Annual World Petrochemical Conference, March 8–12,
Virtual event
www.ihsmarkit.com/events

7th Annual International Congress of Russian LNG, March 17–18,
Baltschug Kempinski Hotel, Moscow, Russia
events@vostockcapital.com
www.lngrussiacongress.com

International Petroleum Technology Conference (IPTC), March 23–April 1, Virtual event
iptc@iptcnet.org
iptcnet.org

Emerson Users Exchange EMEA, March 29–31, Virtual event
Exchange.europe@emerson.com
emersonexchange.org

China International Petroleum & Petrochemical Technology and Equipment Exhibition (CIPPE), March 30–April 1,
New China International Exhibition Center, Beijing
cippe@zhenweiexpo.com
en.cippe.com.cn

APRIL

AFPM Annual Meeting,
April 11–13, Grand Hyatt San Antonio, Texas
(see box for contact information)

Hannover Messe, April 12–16,
Virtual event
P: +49 511-89-34466
www.hannovermesse.de

AIChE Spring Meeting & Global Congress on Process Safety, April 18–23, Virtual event
(See box for contact information)

AFPM Security Conference,
April 19–21, Royal Sonesta Houston, Houston, Texas
(See box for contact information)

CORROSION Conference & Expo, April 19–30, Virtual Event
Lesley.Martinez@nace.org
www.nacecorrosion.org

MAY

API Spring Refining and Equipment Standards Meeting, May 17–20, Hyatt Regency Seattle, Seattle, Washington
P: +1 202-682-8195
registrar@api.org
www.api.org

H_2Tech Solutions, May 18,
Gulf Energy Information Events,
Virtual event
www.H2-TechSolutions.com
info@H2-Tech.com
(See box for contact information)

OPTIMIZE 21, May 18–20,
Virtual event
P: +1 781-221-6400
info@aspentech.com
www.aspentech.com

Easyfairs, Pumps & Valves, May 19–20, Antwerp, Belgium
P: +32 0-3-280-5300
www.easyfairs.com

AFPM International Petrochemical Conference, **May 23–25,**
Grand Hyatt San Antonio, Texas
(see box for contact information)

Industrial XR Leadership Forum, May 25–26, Digital event
P: +1 713-489-6773
innovateenergynow.com

EGYPS, May 31–June 2,
Egypt International Exhibition Center, Cairo, Egypt
egyps.conference@dmgevents.com
www.egyps.com

JUNE

IRPC Process Technology, June 2–3,
Gulf Energy Information Events,
www.HPIRPC.com
(See box for contact information)

7th International LNG Congress, June 7–8, Madrid, Spain
lng@bgs-group.eu
lngcongress.com

HxGN LIVE Global, June 15–18,
The Venetian Resort, Las Vegas, Nevada
hxgnlive.com

Valve World Americas Expo & Conference, June 23–24,
George R. Brown Convention Center, Houston, Texas
P: +1 416-361-7030
s.bradley@kci-world.com
valveworldexpoamericas.com

StocExpo, June 29–July 1,
Antwerp Expo, Antwerp, Belgium
www.stocexpo.com

AUGUST

European Forum for Reciprocating Compressors (EFRC) Conference, Aug. 24–26, Hilton Warsaw Hotel and Convention Centre, Warsaw, Poland
P +49 351-463-32815
www.recip.org

PI World San Francisco, Aug. 30–Sept. 2,
San Francisco, California
www.piworld.osisoft.com

SEPTEMBER

IRPC Operations, Sept. 21–22,
Gulf Energy Information Events
www.HPIRPC.com/Americas
(See box for contact information)

Valve World Asia, Sept. 23–24,
Shanghai New International Expo Center, Shanghai, China
www.valve-world.net

GPA Midstream, Sept. 26–29,
Marriott Rivercenter, San Antonio, Texas
gpamidstreamconvention.org

OCTOBER

AFPM Summit, **Oct. 5–7,**
Hyatt Regency, New Orleans, Louisiana
(See box for contact information)

GasPro 2.0: A Webcast Symposium, Oct. 21,
Gulf Energy Information Events
gasprocessingconference.com
(See box for contact information)

***HP* Awards, Oct. 28,**
Gulf Energy Information Events
www.HydrocarbonProcessing.com/Awards
(See box for contact information)

NOVEMBER

Women's Global Leadership Conference, Nov. 1–2,
Gulf Energy Information Events
www.WGLconference.com
(See box for contact information)

NOTE: Due to the COVID-19 pandemic, industry event dates are constantly changing, while others are being postponed indefinitely or canceled. Please consult the appropriate association or organization to confirm event dates, locations and details.

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TURBOMACHINERY

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Special Supplement to

HYDROCARBON PROCESSING®

Pipeline & Gas Journal

A. BLUME,
Editor-in-Chief

H2TECH

This year, the Gulf Energy Information family expands with the introduction of *H2Tech,* the first technical publication devoted entirely to applications and trends for the hydrogen (H_2) community worldwide. *H2Tech* is geared toward engineers and other professionals involved in H_2 production technologies and applications progress on all spectrums—from gray and brown to blue and green, and beyond.

The midstream sector is reducing its carbon footprint with help from H_2 blending in natural gas pipelines, the use of H_2 in turbomachinery and, in some cases, the repurposing of existing natural gas infrastructure to distribute H_2. Forecasts show that H_2 could reach a 10% share in the world's total primary energy demand by 2050.

H2Tech was created to inform and unite the community of technologists and business professionals working in the rapidly growing H_2 sector. The first quarterly issue of *H2Tech* will be published in March 2021, and the website will host news, podcasts, webcasts, whitepapers, engineering resources and much more. We invite all readers to visit www.H2-Tech.com to stay updated on the H_2 sector and to sign up for the *H2Tech* weekly newsletter. On 18–19 May, the H2Tech Solutions virtual technology conference will bring together engineers, technologists and managers working to advance fuel, chemical and industrial applications for H_2. Visit www.H2-TechSolutions.com to register and submit your abstract. Finally, please feel free to drop me a line with feedback or editorial inquiries for *H2Tech* at Adrienne.Blume@H2-Tech.com. I look forward to hearing from you! **GP**

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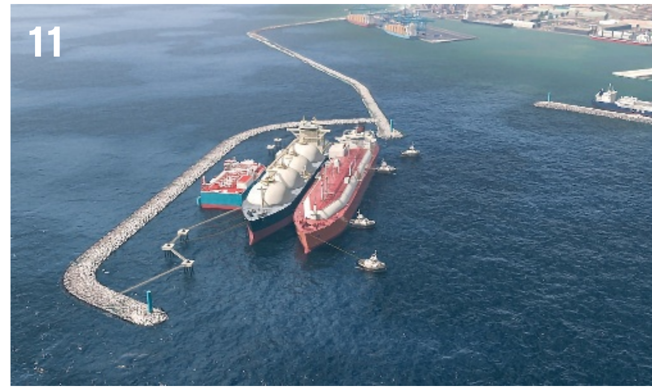

SPECIAL FOCUS: TREATING TECHNOLOGY

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COLUMNS

DEPARTMENTS

Cover Image: Sibur's Nizhnevartovsk gas processing plant near Surgut in West Siberia. Photo courtesy of Sibur.

U.S. FERC approves Alaska LNG import project

U.S. energy regulators approved a plan by Marathon Petroleum Corp.'s Trans-Foreland Pipeline Co. LLC unit to convert the Kenai LNG export plant in Alaska into an import terminal. Trans-Foreland has 2 yr to put the proposed project into service.

The facility would import up to four tanker loads of LNG per year and use its boil-off gas management system to deliver imported gas to the adjacent Kenai refinery. The Kenai LNG export plant entered service in 1969, but it has not exported LNG since 2015.

Nikkiso Cryogenic sells turbo line to Air Liquide

Nikkiso Cryogenic Industries' Clean Energy and Industrial Gases Group, part of Nikkiso Co. Ltd. of Japan, announced the sale of its Turboexpander Business Line to Air Liquide in January. The Turboexpander Business Line designs, manufactures and sells turboexpanders within the industrial gas and NGL industries.

Nikkiso's Cryogenic Service unit will remain an authorized service company and will continue to provide aftermarket services, including repair and servicing of ACD designed and built turboexpander machines, while Air Liquide will provide service activities to its plants and its third-party plant customers. The acquisition was effective January 1, 2021.

Double E seeks approval for Texas-New Mexico gas pipeline

Double E Pipeline LLC has asked U.S. energy regulator FERC for permission to start building its natural gas pipeline project in Texas and New Mexico. Double E is owned by units of Summit Midstream Partners LP (70%) and ExxonMobil Corp. (30%).

Double E Pipeline LLC plans to build a 135-mi (217-km) pipeline to transport 1.35 Bft^{3}d of gas from the Delaware Basin in the Permian Shale in New Mexico and Texas to the Waha Hub in West Texas. Double E is one of several pipelines proposed to transport Permian gas and is expected to enter service in 2021.

ADNOC, Total mark first unconventional gas from UAE

The unconventional gas was delivered from the Ruwais Diyab unconventional gas concession, located 200 km west of Abu Dhabi city, in November 2020. The achievement marks a significant milestone toward future full field development and is an important step toward ADNOC's target of producing 1 Bsft^{3}d of gas from the concession before 2030, ultimately enabling gas self-sufficiency for the UAE.

The unconventional gas is delivered through a purpose-built gas pipeline and centralized early production facility in the Diyab field, which enables distribution through ADNOC's gas network. The accelerated progress and strong collaboration between ADNOC and Total enabled the companies to fast-track the exploration of the unconventional gas resources while tailoring operations to the UAE's shale play type.

The milestone builds on ADNOC's continuous efforts to de-risk unconventional gas resources across Abu Dhabi since 2016 and comes just over a year after the country announced the discovery of 160 Tsft^3 of unconventional gas recoverable resources.

Sempra to move forward with Costa Azul LNG

Sempra Energy's ECA Liquefaction subsidiary will build the Costa Azul LNG export plant in Mexico, the only LNG export project in the world to get a final investment decision (FID) in 2020. The government awarded the export permit on the condition that the project will help offset an oversupply of gas in the area. Sempra had been waiting for the export permit all year, due to delays caused by the spread of the COVID-19 pandemic.

ECA Liquefaction is a JV between Sempra LNG and Sempra's Mexican subsidiary, Infraestructura Energética Nova SAB de CV (IEnova). The \$2-B terminal is expected to produce first LNG in late 2024. The plant, which will have a nameplate capacity to produce about 3.25 metric MMtpy of LNG, already has 20-yr agreements with units of Mitsui & Co. Ltd. and Total SE for the purchase of 2.5 metric MMtpy from the project's first phase.

Costa Azul's Pacific Coast location gives it an advantage over competing U.S. Gulf Coast export plants because it is closer to growing Asian markets. U.S. terminals usually ship LNG to Asia through the Panama Canal.

O&G industry commits to new methane emissions reporting

In a move that will help tackle one of the largest and most solvable contributors to the climate crisis, 62 major players in the oil and gas industry that represent 30% of global oil and gas production have agreed to report methane emissions with a new, higher level of transparency.

The Oil and Gas Methane Partnership (OGMP) is a Climate and Clean Air Coalition initiative led by the UN Environment Program, the European Commission and the Environmental Defense Fund. At the core of the effort is a comprehensive, measurement-based methane-reporting framework (OGMP 2.0) that will make it easier for officials, investors and the public to accurately track and compare performance across companies in ways that have not been possible to this point.

Crucially, the OGMP 2.0 includes not only a company's own operations, but also the many JVs responsible for their production. The OGMP 2.0 framework applies to the full oil and gas value chain, including midstream transportation and downstream processing and refining. To support the realization of global climate targets, OGMP 2.0 aims to deliver a 45% reduction in the industry's methane emissions by 2025, and a 60%–75% reduction by 2030.

Azerbaijan starts gas exports to European market

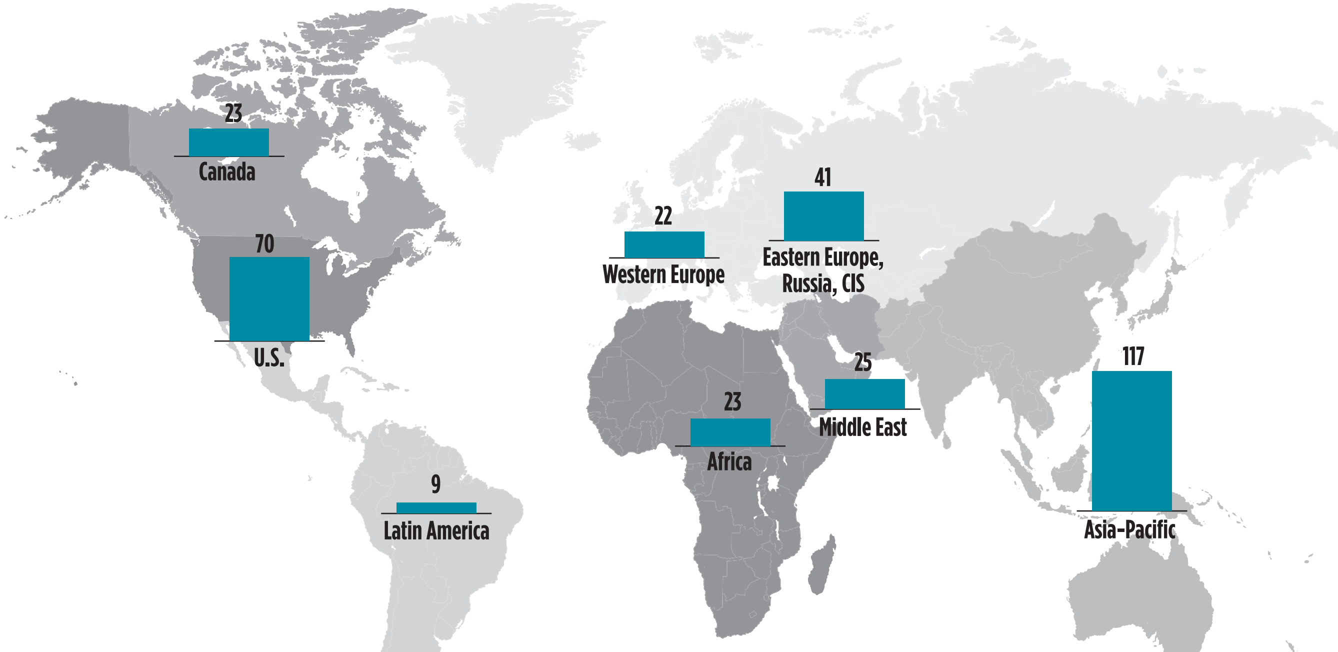
Azerbaijan has started commercial natural gas supplies to Europe via the Trans Adriatic Pipeline (TAP), beginning its push into the lucrative energy market dominated by Russia. The project has the backing of the European Commission as part of efforts to curb Europe's dependence on Russian energy. Russia controls 34% of Europe's gas market and plans to raise gas exports to Europe, including Turkey, to 183 Bm^3 in 2021 from the 171 Bm^3–172 Bm^3 expected for 2020. Europe's annual consumption stands at around 500 Bm^3, used mostly in power generation.

TAP is a part of the \$40-B Southern Gas Corridor, stretching 3,500 km from Azerbaijan to Europe and drawing from Azerbaijan's giant Shah Deniz II field in the Caspian Sea. Azerbaijan aims to supply European gas markets with 10 Bm^{3}y of gas, including 8 Bm^3 to Italy and a combined 2 Bm^3 to Greece and Bulgaria. It already supplies gas to Turkey.

Azeri gas is unlikely to change Russia's dominant position in Europe, but it still poses some threat to Russia's share of the EU gas market. Russia, meanwhile, is seeking to complete its subsea Nord Stream 2 gas pipeline project to Germany, which stalled a year ago due to U.S. sanctions.

LEE NICHOLS, Editor-in-Chief/Associate Publisher, *Hydrocarbon Processing*

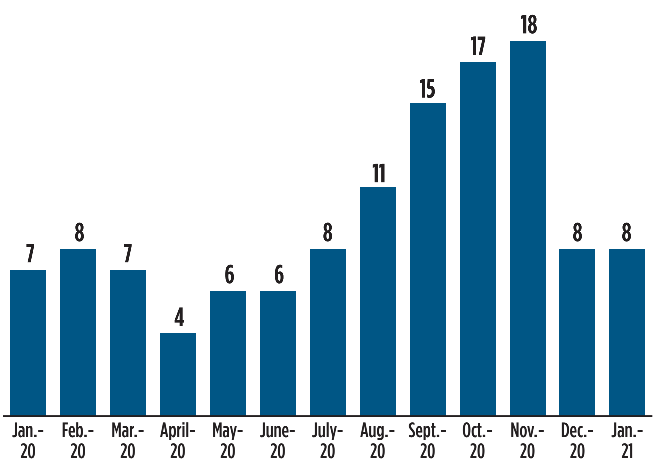
Hydrocarbon Processing's Construction Boxscore Database and Energy Web Atlas are tracking 330 active gas processing/LNG projects in the hydrocarbon processing industry. Most of these projects—approximately 35%—are in the Asia-Pacific region, followed by the U.S. (21%). Due to additional lockdowns and restrictions stemming from a resurgence in the COVID-19 virus, new gas processing/LNG project announcements showed a drop in the last two months of 2020. However, with COVID-19 vaccines being distributed, 2021 may be a rebound year in natural gas consumption, resulting in additional capital being spent to supply increased demand, especially in Asia. **GP**



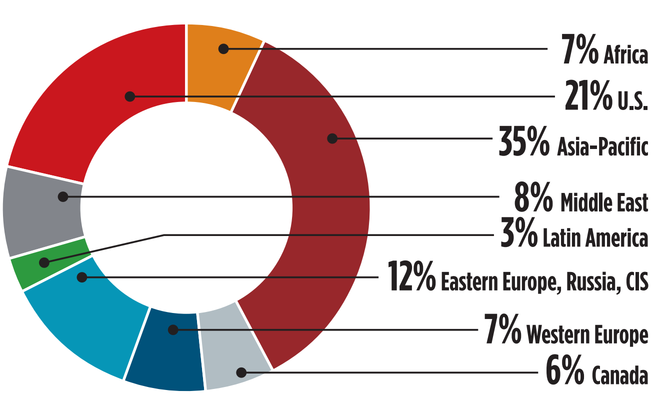
Active gas processing/LNG projects by region

Source: Energy Web Atlas and the Construction Boxscore Database

New gas processing/LNG project announcements, January 2020–January 2021

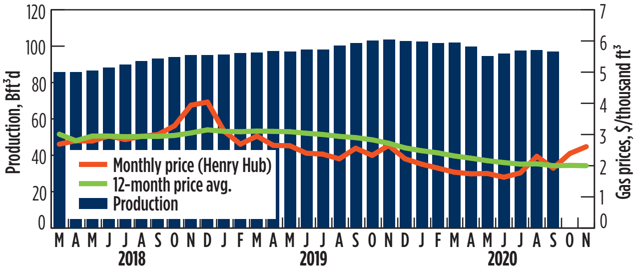


Active project market share by region



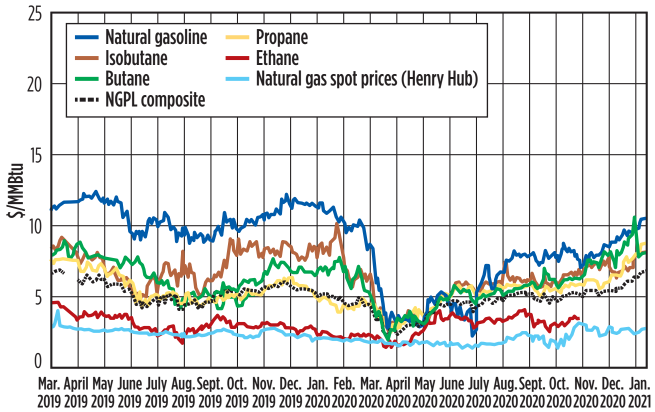
U.S. exports of LNG set a new record in December 2020, averaging 9.8 Bft³d, according to the U.S. EIA. The December volume is more than three times higher than the reduced export levels seen in summer 2020. Contributing to the higher exports were factors such as higher demand in key Asian markets on colder-than-normal winter temperatures and unplanned outages at LNG export terminals in Australia, Qatar, Malaysia, Norway, Nigeria and Trinidad and Tobago. The reduction of LNG supplies led to upticks in natural gas and LNG prices in Asia and Europe, attracting higher volumes of flexible LNG supplies from the U.S. **GP**

U.S. gas production (Bft³d) and prices ($/Mcf)

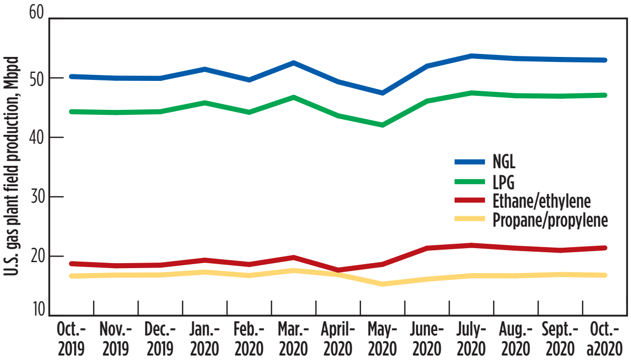


Production equals U.S. marketed production, wet gas. Source: EIA.

U.S. natural gas spot prices at Henry Hub and NGL spot prices at Mont Belvieu, $/MMBtu



U.S. natural gas plant field production of NGL, LPG, ethane and propane, Mbpd



Source: U.S. EIA

Developing LNG infrastructure for West Africa's gas-to-power push

S. OIRERE, Contributing Writer

In West Africa, governments have embraced the use of gas as a low-carbon fuel to increase electricity generation, which is creating additional demand for LNG. Although Africa has substantial gas reservoirs, the needed LNG supply is presently sourced from the international market as leading producers in the region grapple with supply challenges. These challenges can be partly solved, however, through investment in modern gas storage facilities.

Natural gas production is still in its infancy in Ghana, Senegal and Côte d'Ivoire. Gas storage infrastructure, especially underground storage, has not yet been achieved since gas reservoirs in producing countries have not yet been depleted. This means that West African nations' gas-to-power campaigns require other forms of gas storage to ensure support for electricity generation that, at the moment, relies heavily on imported LNG.

Advancing LNG infrastructure in West Africa. Investment in LNG import infrastructure is an emerging trend in West Africa as leading natural gas producers such as Nigeria, Ghana, Côte d'Ivoire, Senegal, Equatorial Guinea and Benin grapple with challenges that have constrained the consistency of their gas production.

The region's natural gas producers are still courting international oil companies with opportunities in their upstream spaces, but production has remained inadequate to support increased power generation requirements. This has led to a shift in focus to the construction of LNG regasification and storage facilities.

For example, Nigeria, Côte d'Ivoire, Ghana and Senegal—the leading gas-to-power markets in West Africa—have plans to generate a combined additional 7,759 MW of power from gas by 2030, of which 2,222 MW is projected to come online by 2025. To realize this plan, the countries' governments have entered into agreements with international gas suppliers to supplement their inadequate domestic supply. They have also drawn up LNG storage projects to meet the seasonal demand expected from end users, such as electricity generation plants and industrial users.

Ghana pushes ahead with Tema LNG. Ghana is targeting an additional 1,718 MW of power generation from gas by 2030. In partnership with the private sector, the government has invested in new commercial LNG import infrastructure, namely the Tema LNG import terminal (**FIG. 1**). At present, Ghana relies on the 678-km West African Gas Pipeline for its gas supply; however, the pipeline has a historically erratic supply trend due to payment disputes, technical issues and upstream gas supply issues with Nigeria.

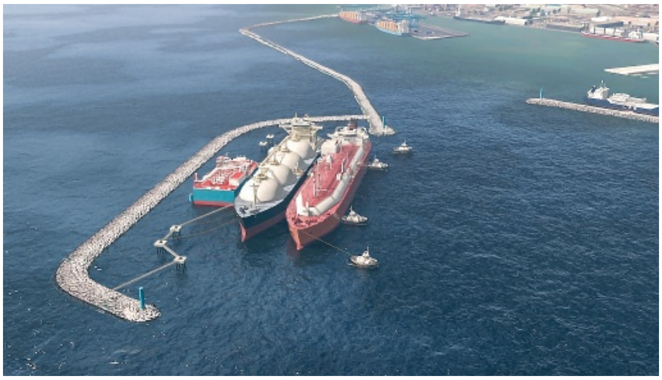


FIG. 1. The planned Tema LNG import terminal offshore Ghana. Image courtesy of Tema LNG Terminal Co.

The previous approval of a concession by Tema LNG Terminal Co. Ltd. (Tema LNG), a JV between Helios Investment Partners and Ghana National Petroleum Co. (GNPC), for the construction of an LNG import terminal was a major step in Ghana's efforts to hedge available gas supplies for power generation. GNPC previously signed a 12-yr gas supply agreement with Rosneft Trading SA for the supply of 1.7 metric MMtpy of gas to serve the Tema region.

Under the supply agreement, GNPC will purchase LNG from Rosneft Trading for regasification and subsequent delivery to thermal independent power producers and industrial customers. In accordance with the plan, Rosneft Trading has signed an agreement with Tema LNG Terminal Co. for the development of a 240-MMsft^{3}d LNG import terminal that will be linked to a floating storage unit (FSU) and a floating regasification unit (FRU). The FRU arrived offshore Ghana in early January 2021.

The Tema LNG terminal project was preceded by a similar deal between GNPC and Bermuda-based LNG shipping company Golar for the supply of 170,000 m^3 of gas from the Golar *Tundra* FSRU to support Ghana's LNG imports.

Côte d'Ivoire eyes FSRU. In Côte d'Ivoire, where gas is a critical part of the country's energy mix, the government is working to fast-track modern LNG import infrastructure to regasify and store LNG for distribution to end users.

The country has an estimated 1 Tft^3 of developed gas resources, but this is inadequate to meet demand; Côte d'Ivoire has an estimated gas deficit of 0.35 Tft^{3}y. Additional gas must be imported, regasified, stored and distributed to support the planned generation of 1,271 MW of gas-fired electricity by 2030.

Earlier, French oil major Total led a team of partners to sign an agreement for the development of a 3-MMtpy LNG regasification terminal in Côte d'Ivoire. Other companies involved in the LNG project, in which Total is the operator with a 34% stake, include national firms PetroCI (11%) and CI Energies (5%), as well as SOCAR (26%), Shell (13%), Golar (6%) and Endeavor Energy (5%).

Total will supply up to 0.5 metric MMtpy of LNG for the regas terminal over a 15-yr period, making it possible for Côte d'Ivoire to integrate LNG supply and import infrastructure through an FSRU. A pipeline would connect the FSRU in the Vridi, Abidjan area to existing and planned power plants in Abidjan, as well as to regional markets connected to the Ivorian network. Total said the project will enable Côte d'Ivoire to become the first regional LNG import hub in West Africa and to meet both regional and domestic demand.

Other LNG and gas-to-power initiatives. Total is also developing an LNG import terminal in neighboring **Benin.** The project includes an FSRU and an offshore pipeline connection to existing and planned power plants in Maria Gléta. According to Total, Benin's access to LNG will help the country meet growing domestic energy demand and add more natural gas to the country's energy mix, thereby reducing its carbon intensity.

In **Equatorial Guinea,** a regasification plant to support the storage, transport and distribution of LNG across the country has been developed. The complex includes at least 12 bullet tanks with a capacity of 14,000 m^3 of storage capacity. The regasification plant, located at the Akonikien port, is the first LNG storage and regasification plant in West Africa and falls under Equatorial Guinea's government-led LNG2Africa initiative.

Meanwhile, an 84,100-m^3 LNG storage tank is being developed in **Nigeria** as part of the $6.5-B Nigeria LNG Ltd. (NLNG) Train 7 project, which also includes a new liquefaction unit, a 36,000-m^3 condensate tank and three gas turbine generators on Bonny Island. The development of gas storage facilities is a boost for Nigeria's gas-to-power scheme, partly because of the uncertainty of gas supply from key producing areas, such as the Niger Delta, where frequent vandalism starves power plants of the needed gas. Nigeria selected a consortium comprising Saipem, Chiyoda and Daewoo as the EPC contractor for the Train 7 project.

One of West Africa's smallest gas producers, **Senegal,** has made recent additional natural gas discoveries but is in need of infrastructure to support LNG imports for gas-to-power projects. With no new local gas production expected until 2025, Senegal has opportunities for LNG imports to ease its transition to gas while also reducing the cost of its electricity generation. **GP**

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Caustic treatment design, integration and waste disposal for gas plants

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Gas processing plants offer a very different landscape than the typical oil refinery, and the methods used to treat sulfur (S) compounds in the liquids must be adjusted accordingly. When it comes to caustic treatment, one of the first configuration decisions is whether to treat the C_3–C_{10}+ NGL stream in a single unit or to fractionate prior to caustic treatment. Treating the entire hydrocarbon stream may result in less equipment, but fractionating can result in better selectivity for product specifications.

Depending on the hydrocarbon source, LPG streams will have a vastly different distribution and concentration of mercaptan molecules, which require more rigorous removal methods. Some contaminants, such as H_2S, CO_2, and mercaptan (RSH), can be removed from the LPG stream by caustic, referred to as extraction. Other contaminants, including COS, CS_2 or dimethyl sulfide (DMS), cannot be extracted from the hydrocarbon with caustic alone.

Furthermore, the C_5+ condensate streams also differ from typical refinery naphtha streams. These streams can contain very high levels of mercaptan that cannot be sufficiently removed by caustic treatment. In this case, the mercaptan species must be converted to disulfides in an alkaline environment over a fixed bed of catalyst to meet pipeline specifications. This process is referred to as "sweetening" because the mercaptans are converted and the S content of the hydrocarbon does not change. Other feed impurities will affect the design of the pretreatment and metallurgy of the unit.

This article covers the most common impurities found in caustic waste streams and how they affect the design and placement of treating units in the midstream gas processing flow scheme. These caustic treating systems also generate waste streams for disposal. As regulations on caustic disposal and S oxides (SO_X) emissions tighten, it is worth considering alternative options for disposal of spent caustic, disulfide oil and spent air to meet ongoing and future changes in regulations.

Caustic treatment. Midstream gas processors historically have used different technologies to remove or treat acidic impurities in liquid hydrocarbon streams.

Caustic treatment remains the most economical process when removing mercaptans. Fractionation, which occurs prior to caustic treatment, cannot remove mercaptans efficiently from the hydrocarbon cuts because they form azeotropes with the hydrocarbon. **TABLE 1** shows that mercaptans have higher boiling points than the hydrocarbon compounds with which they boil. As a result, the mercaptans will distribute throughout various lighter hydrocarbon fractions. Since the strong base, sodium hydroxide (NaOH or caustic), chemically reacts to remove acidic molecules H_2S, CO_2 and mercaptans, it can be used to remove the mercaptans or convert them, depending on the mercaptan type.

Different methods of caustic treatment are used to remove contaminants from the liquid stream, meeting S specifications for pipeline mercaptan limits, downstream processing requirements, process unit feed requirements, and propylene specifications.

Alternatives in caustic treatment. Caustic treatment can be generalized into two different methods: extraction and sweetening. Extraction is where mercaptans are removed from the hydrocarbon to form low-S products. Fresh caustic can be used to remove H_2S, CO_2, and mercaptan from these streams with a once-through caustic contact scheme. However, once-through caustic extraction has a high fresh caustic cost and a high disposal cost. To offset this, most customers choose to catalytically regenerate the caustic, using air to convert and remove the extracted mercaptans while returning the caustic to the extractor with minimal S content. This regeneration method has a higher capital cost than once-through caustic usage but a much lower operational cost, due to the vast reduction in caustic consumption and disposal quantities.

TABLE 1. Boiling points of different compounds

	Boiling point, °F		
Compound	Observed	True	
Carbonyl sulfide	–58		
Propylene	–54		
Propane	–44		
Methyl mercaptan	9.5	43	
i-Butane	10.9		C_3–C_4 range
i-Butene	20		
1-Butene	21		
n-Butane	31		
Ethyl mercaptan	63	95	
3-Methyl-1-butene	68		

Most customers choose to catalytically regenerate caustic, using air to convert and remove the extracted mercaptans while returning the caustic to the extractor with minimal sulfur content. This regeneration method has a higher capital cost than once-through caustic usage but a much lower operational cost.

The other type of caustic treatment is sweetening, which requires injection of air that dissolves into the hydrocarbon. The oxygen from the dissolved air and the mercaptan already present in the hydrocarbon react in the presence of the solid bed catalyst and create disulfide that remains in the liquid hydrocarbon stream. This disulfide present in the product is less corrosive than the mercaptan in the feed, despite no change in the total S. Caustic is easily separated from the hydrocarbon in the reactor vessel while spent air is separated from the hydrocarbon, either in a degassing vessel in the process or in downstream tankage, depending on the volume of spent air. Sweetening can be used to treat naphtha (C_5–C_{12}) and to produce jet fuel (C_{12}–C_{20}+) hydrocarbons.

Pros and cons to fractionation prior to caustic treatment. Treating the entire NGL stream without fractionation allows for minimum capital investment, but minimum efficiency.

Using one caustic concentration results in poor selectivity for mercaptan reaction or removal. In addition, contamination of caustic from pipeline chemicals can include interfering ions, acids, pipeline slip and flow enhancers, and upstream processing chemicals. Treating this variety of contaminants can increase fresh caustic consumption and spent caustic disposal. Entire-stream extraction preferentially removes light mercaptans as opposed to larger mercaptans. Heavy mercaptans remaining in the hydrocarbon would likely cause off-specification product (see **FIG. 2**).

Conversely, entire-stream sweetening can better convert most of the heavy mercaptans to disulfide in the presence of lower-strength caustic. This will cause a loss of light hydrocarbon from spent air vented from the hydrocarbon. Additionally, this process would need to have large fixed-bed reactors to accommodate the liquid flow and required space velocity.

Fractionation and individual treatment of narrowly cut fractions maximizes treating efficiency. Using the most effective caustic concentration for each treating objective optimizes selectivity for mercaptan removal or conversion.

Extraction designs are extremely flexible and can be optimized for mercaptan removal from lighter feeds [C_1 and C_2 (gas phase) and C_3 to C_5 (liquid phase)] containing 2 wppm mercaptan S–20,000+ wppm mercaptan S in one or multiple tight cut extractors. This process can be designed to achieve minimum reentry of S, reducing the S to less than 5 wppm S in the product, and in some cases less than 1 wppm S. Since heavy mercaptans are not in this cut, stronger caustic can be used, which increases the efficiency of the extractor, reduces caustic circulation rates and reduces vessel sizes.

Heavier condensate feeds (C_5–C_{20}+) will contain heavier mercaptans with concentrations ranging from 20 wppm S to 2,000+ wppm S. These streams are more efficiently treated via sweetening with weaker caustic strengths to increase heavy mercaptan solubility. Since the treated hydrocarbon has low vapor pressure, minimum loss of hydrocarbon product occurs with the spent air vented from the hydrocarbon. Smaller-size fixed-bed reactors can accommodate the liquid flow at the required space velocity for the desired conversion. As a result, mercaptans are sweetened to disulfide to less than 5 wppm mercaptan S for naphtha and less than 20 wppm mercaptan S for jet fuel.

Additionally, the product naphtha can be fractionated to concentrate heavy disulfide S formed from sweetening the mercaptans in the heavy cut, leaving a sweet, saleable light cut of naphtha.

Typical and atypical impurities, and effect on design. Several common impurities, such as CO_2, COS, H_2S and RSR, can exist in the feed to the systems. Although it is expected that entire-stream amine treating and fractionating of the ethane cut would remove all the CO_2 in the C_3 and C_4 cuts, CO_2 has been observed in these cuts at midstream facilities to the concentration of 100 wppm–1,000 wppm. Caustic can be used to completely remove CO_2 and H_2S, but it is consumed irreversibly and would represent an operating cost in the range of millions of dollars.

The preferred method of treatment at these high concentrations is an amine absorber to reduce the concentration to less than 25 wppm, followed by a caustic prewash upstream of the caustic treater. COS can be removed to less than 1 wppm by pretreatment in a proprietary prewash design,[a] or during post-treatment with a modified caustic blend.[b]

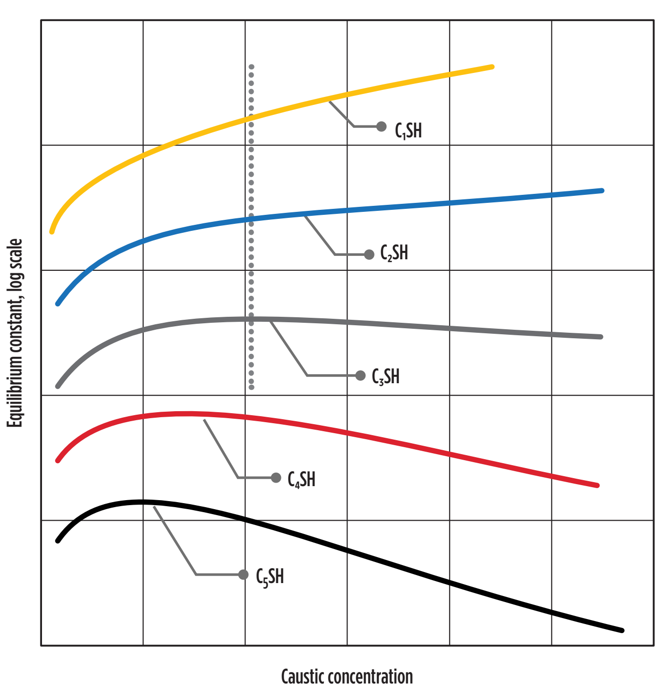

FIG. 1. Mercaptan extraction curve.

Even though the typical impurities are present, atypical impurities can affect the design of a complex. These atypical impurities include oxygen, methanol, glycol, corrosion inhibitors, naphthenic acids and unusual mercaptan distributions. Various corrosion inhibitors and slip enhancers will initiate and stabilize emulsions between hydrocarbons and caustic. In addition, methanol can come from many upstream sources (e.g., dehydrators) and form emulsions with caustic. Excessive methanol quantities should be removed with a water wash prior to amine or caustic treating. Additionally, shared regeneration sections, discussed later in this article, transfer methanol from one segregated stream to another.

Glycol and other oxygenates also must be considered. These impurities can cause acid corrosion in sweetening units. Two options exist to minimize the occurrence of acid corrosion.[c] The first option is to construct the existing reactors from 316L stainless steel. The second option is to apply special epoxy to the carbon steel and concrete surfaces. This creates an epoxy layer to protect the carbon steel of the reactor. However, the epoxy will need to be replaced at every turnaround of the unit.

Integration of caustic treating with the complex. Different options exist to integrate caustic treating units into a grassroots or existing plant. One configuration may treat the entire LPG stream with caustic extraction for use as power plant fuel, low-S motor fuels, or sales to other processors.

One example, shown in **FIG. 2**, places a C_3 extraction process unit just after the depropanizer, thereby producing low-S propane required by a dehydrogenation process to produce propylene. Butanes from the debutanizer are treated in the C_4 extraction process unit, which creates a low-S C_4 cut for further fractionation by the deisobutanizer to generate low-S isobutane and n-butane. The caustic is rich in mercaptides from both the C_3 and C_4 extraction systems and are sent to a common regeneration system to reduce capital cost.

Ultra-low-S specifications of less than 2 wppm total S can be reached in the extraction products by installation of a newly designed disulfide scrubber to drastically reduce the disulfide present in the regenerated caustic. The disulfide scrubber[d] virtually eliminates reentry of S into the product streams by counter-currently contacting the caustic stream with a hydrocarbon stream, reducing the total product S by more than 95% over a design without it.

The bottoms of the debutanizer can be processed through a naphtha sweetening process.[e] This process treats C_5–C_{12}+ to less than 5 wppm mercaptan S with minimum alkalinity requirements, which can then be used to dilute bitumen when creating synthetic crudes.

Another option after sweetening is fractionating the naphtha to produce a low-S C_5 and C_6 material.[f] Fractionating out the light C_5 and C_6 material concentrates the heavy disulfides created during the sweetening process in the bottoms product.

Methods for disposal of waste caustic and spent air. Caustic prewashing is necessary to completely remove the residual H_2S and CO_2 from the feed hydrocarbon. It is used upstream of the extraction process so that the feed is free of H_2S and CO_2, which creates an S-laden caustic stream that must be disposed of.

During the extraction process, mercaptan transfers from oil to the aqueous caustic phase. The generated sodium mercaptide remains in the caustic, which is then separated from the hydrocarbon phase. The sodium mercaptide is then catalytically oxidized with injected air at almost ambient conditions to produce disulfide, which separates from the caustic. This regeneration process creates an S-laden spent air stream, caustic stream and disulfide oil stream that must be disposed of (**FIG. 3**). The naphtha sweetening process also makes use of caustic and will produce a waste caustic stream that must be disposed of.

After the extraction and/or sweetening processes have been completed, several methods exist to dispose of the effluent waste caustic, disulfide oil and spent air from the treating units. Each of these effluent streams have different disposal

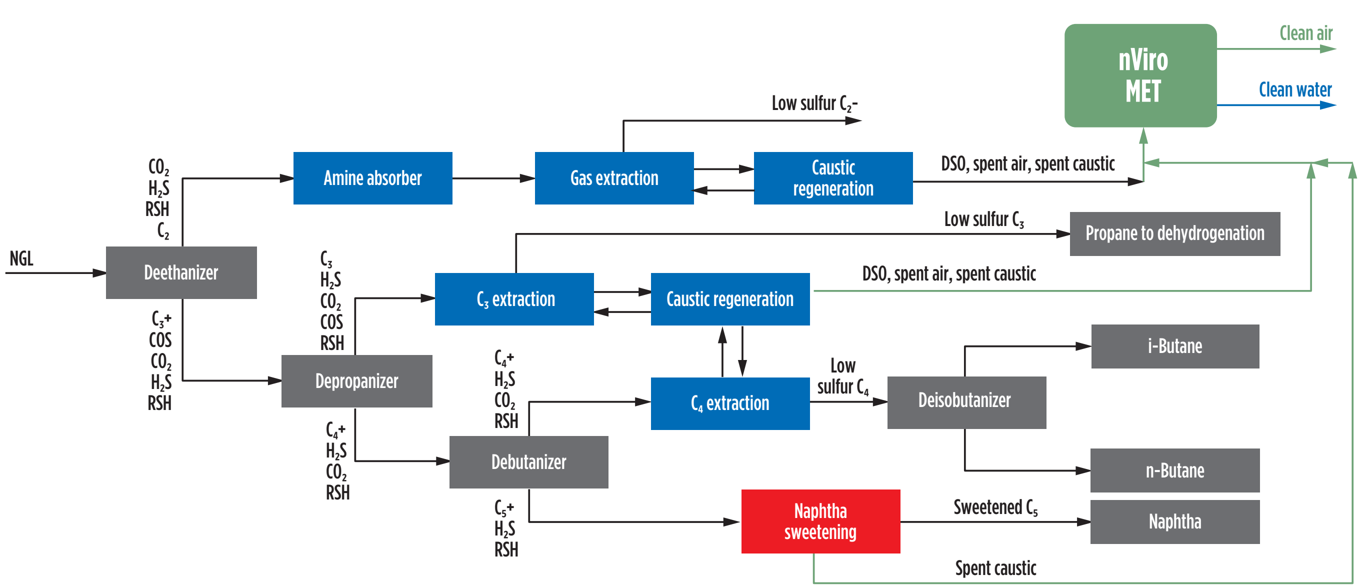

FIG. 2. An example integration of caustic treatment into an existing plant.

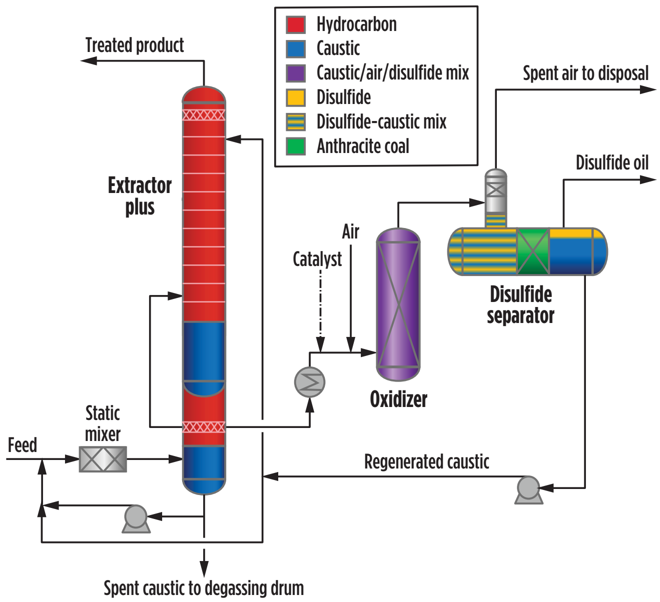

FIG. 3. Sulfur streams are spent air to disposal, disposal oil and spent caustic to degassing drum.

methods, depending on acceptable environmental regulations. As emission regulations continue to tighten, the disposal of these effluent streams will come under greater scrutiny. Minimizing environmental impact through use of greener technology alternatives is becoming the best practice to process these streams.

Typical disposal methods for spent caustic include:

- **Paper mills:** These mills use sulfidic caustic in the manufacture of caustic. If the midstream facility is near a paper mill, a regeneration section may not even be necessary, since the paper mill will likely pay the fresh caustic cost to take the caustic.
- **Deep well:** The waste caustic is pumped back into a well belowground. This is the least expensive alternative; however, consent decrees allowing this practice are expiring, and environmental agencies are unlikely to renew them.
- **Wet air oxidation methods:** Sulfidic caustic catalytically converts to salts in a reactor while reducing chemical oxygen demand (COD) and biochemical oxygen demand (BOD) by 50%–95%. Various installation costs and recurring operating and catalyst costs are involved. Units are difficult to operate due to salting out and reactor bed plugging.
- **Acid neutralization:** A mineral or strong organic acid is used to neutralize the caustic. H_2S, mercaptans and other acid gases evolved from the solution are either incinerated or captured by other technologies, creating more disposal issues.
- **Waste hauler:** A special waste hauler picks up the caustic from the site and disposes of it; the cost could exceed millions of dollars per year.
- **Green disposal unit:** Generates a 100% environmentally compliant liquid or solid stream[g] (FIG. 3).

The current disposal methods for disulfide oil include:

- **Deep well:** See previous section
- **Combination with sweetened naphtha:** The combined stream can be sold as bitumen diluent
- **Waste hauler:** See previous section
- **Incineration in a combustor:** SO_X and other consent-decree gases are generated
- **Green disposal unit:** Generates a 100% environmentally compliant liquid or solid stream (FIG. 3).

The current disposal method for spent air includes:

- **Vent to atmosphere:** Typically needs activated carbon canisters or special consent decrees for the strong, objectionable disulfide and mercaptan smell
- **Incineration in a combustor:** See above
- **Green disposal unit:** Generates a 100% environmentally compliant liquid or solid stream (FIG. 3).

Takeaway. Caustic treatment is an important part of gas processing operations to combat impurities to prevent corrosion and to meet a variety of regulations. Many impurities need to be considered when designing a treatment plan, including the boiling points of different compounds, as well as chemical reactions.

Extraction and sweetening processes are solutions to caustic treatment that can be designed for greenfield installations and retrofitted into existing plants to maximize efficiency and provide a cleaner feed to further downstream processes. Each customer is faced with specific constraints, and licensors can provide guidance on the tradeoffs between entire-stream or partial-stream treating to meet CAPEX and OPEX objectives.

Additionally, these treating processes can be combined with the state-of-the-art effluent disposal technology to provide a greener, more-flexible effluent treatment solution to meet the processor's needs and regulation requirements. **GP**

NOTES

[a] UOP's Enhanced Prewash design
[b] UOP's post-treatment COS removal section
[c] Observed and diagnosed by UOP at various midstream facilities
[d] UOP disulfide scrubber
[e] UOP Minalk sweetening unit
[f] UOP SweetFrac
[g] UOP Callidus' nViro Met

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Increase separation efficiency with enhanced slug catcher internals

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Gas facilities use slug catcher vessels to separate arriving gas and liquids. These vessels are typically three-phase separators designed with vane-type mist eliminators. Mist eliminators are not highly efficient in eliminating the liquid carryover from the slug catchers, which will affect downstream separation processes, such as acid gas removal units.

This article discusses enhancements created for the slug catcher's internals to achieve higher separation efficiency and minimize the process design, sizing, material grade and future inspection and maintenance impact on downstream processing units at Saudi Aramco's Tanajib gas plant project in Saudi Arabia.

Issues with existing slug catcher system. Highly effective separation of oil and gas from different impurities during upstream operations is a matter of paramount importance. All downstream activities and the process equipment service life depends on the purity level obtained in these first steps.

Historically, slug catcher vessels designed with vane-type mist eliminators are not very effective in eliminating the liquid carryover from the slug catchers. The impurities in liquid carried over have a direct negative impact on downstream separation processes (e.g., acid gas removal units), directly affecting the process design, sizing and material grade selection. Simultaneously, the entrained solid particles can cause fouling of the demisting mesh pads and other downstream components, significantly increasing inspection and maintenance costs and timelines.

At the Tanajib gas plant, it was found that mist eliminators or a vane pack alone were not effective in the separation of small liquid droplet sizes (i.e., smaller than 2 μm); therefore, they were not capable of removing most of the droplets, resulting in a very low separation efficiency and high liquid carryover. When the operating pressure was above 870 psig/60 barg (typical for inlet facilities), the droplets were usually smaller and the efficiency of separation was, therefore, vulnerable. Furthermore, the plant's processing capacity was often reduced to minimize the accumulated liquids in the downstream scrubber of slug catchers, with frequent draining required for this scrubber.

With myriad problems faced in the Tanajib plant's original slug catcher design, the following design considerations were reviewed extensively, which resulted in the following stringent design requirements:

- Maintain the liquid carryover from the slug catchers equal to or below 0.1 gal/MMsft^3.
- Maintain separation efficiency of 98% for droplets larger than 10 μm.

Existing slug catcher designs. Two designs for slug catcher configurations are discussed in the following sections.

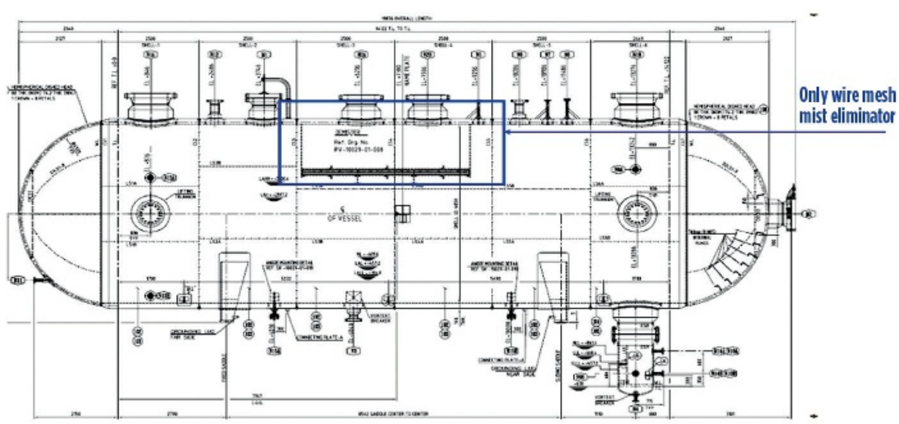

FIG. 1. Slug catcher example from existing facilities.

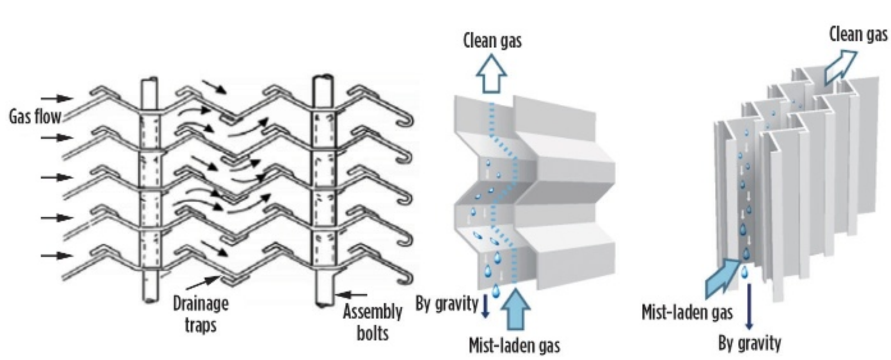

FIG. 2. Typical vane pack configuration.

Historically, slug catcher vessels designed with vane-type mist eliminators are not very effective in eliminating the liquid carryover from the slug catchers. The impurities in liquid carried over have a direct negative impact on downstream separation processes, directly affecting the process design, sizing and material grade selection.

Slug catcher 1 design. Slug catchers in many existing facilities are designed with vane-type mist eliminators (FIG. 1). The specified efficiency of 98% for droplets larger than 10 μm and carryover of liquid < 0.1 gal/MMsft^3 required for the Tanajib plant would not be achieved using a vane pack mist eliminator, mainly because of the very high operating pressure of the slug catchers.

Historically, a vane pack (FIG. 2) was found to be unsuitable for operating pressure above 60 bar due to the fact that a small liquid droplet size will be expected due to the high pressure of the vessel. The vane pack will not be capable of removing most of these droplets, resulting in very low separation efficiency and high liquid carryover.

Slug catcher 2 design. In a second slug catcher design configuration, the existing design had only a wire mesh mist eliminator at the gas outlet nozzle. Due to the high gas load factor, the mist eliminator would not be able to achieve the required separation efficiency (FIG. 3).

Design improvements.

Improvements to the designs of both slug catchers were implemented, as outlined in the following sections.

Slug catcher 1 improvements. To achieve 98% efficiency (for droplets > 10 μm) and 0.1 gal/MMsft^3 carryover, axial cyclonic mist eliminators were deployed to further increase slug catcher performance. The top section of the calming baffle was equipped with a proprietary, fouling-resistant vane pack[a] preconditioner. This supports the demisting operations by coalescing the liquid droplets to form larger aggregates that are easier to be captured.

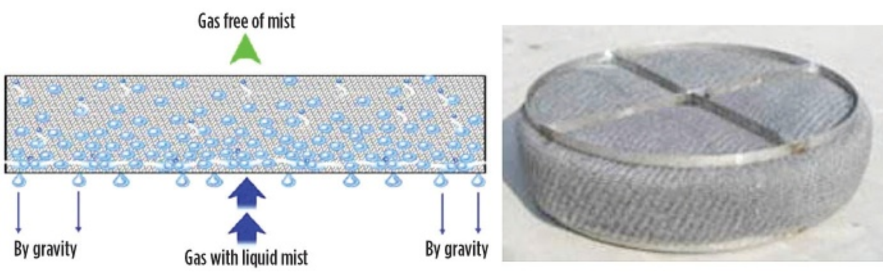

FIG. 3. Typical wire mesh mist eliminator configuration.

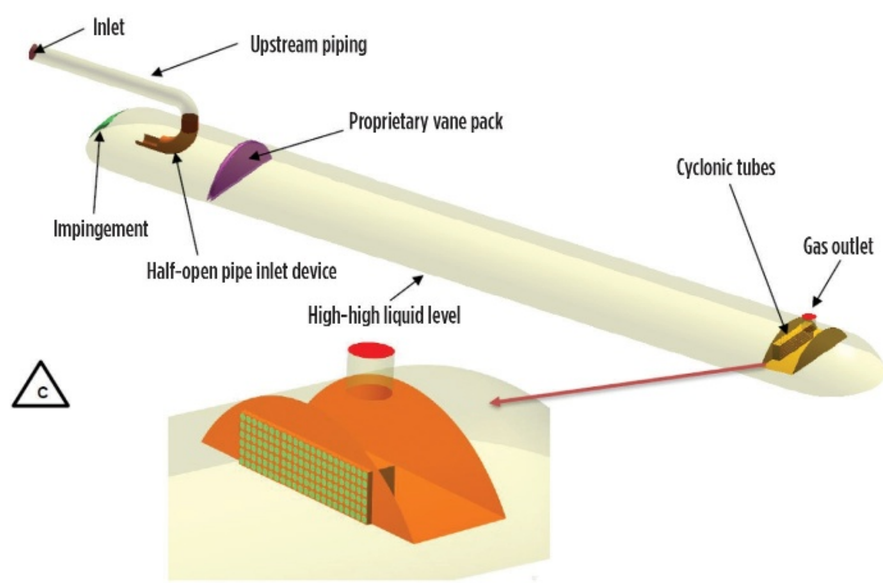

FIG. 4. Illustration for a slug catcher with baffles and an axial mist eliminator.

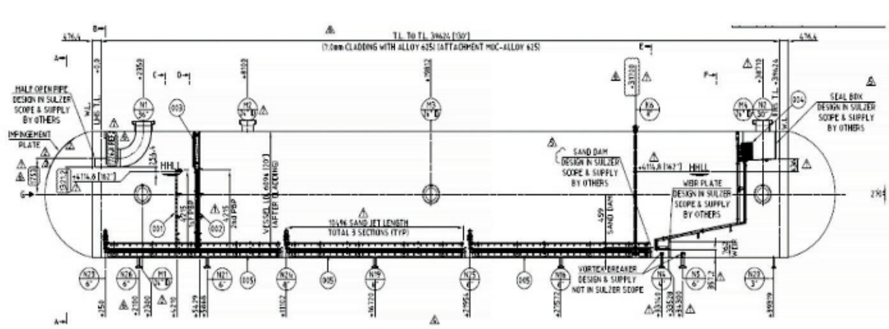

FIG. 5. Revised slug catcher design drawing with new internals.

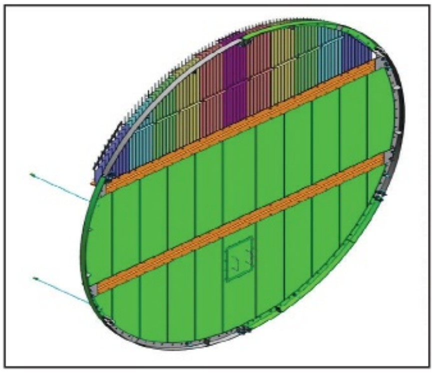

FIG. 6. Proprietary vane-type mist eliminator[a] preconditioner.

Additionally, a horizontal-flow axial cyclone was identified as an ideal high-capacity system able to remove all liquid droplets while withstanding fouling.[b]

Slug catcher 2 improvements. To achieve 98% efficiency (for droplets > 10 μm) and 0.1 gal/MMsft^3 carryover, a cyclonic mist eliminator design was found to be an ideal solution based on design validation. The same horizontal-flow axial cyclone[b] was used as for slug catcher 1.

Design validation. The design was validated by simulating the coalescing and separation efficiency by a computation fluid dynamics (CFD) model. In the CFD study, the following assessments were carried out for the performance of the slug catcher:

1. The separation of two-phase flow consisting of gas and liquid, with single-phase gas flow simulations.
2. The effect of gas flow on liquid interface.
3. Carryover of liquid particles.

The CFD simulations proved that two perforated inlet distribution baffles, together with the proprietary vane pack[a] and the horizontal-flow axial cyclone[b] deck at the outlet nozzle of the slug catcher, provided outstanding demisting performance that met the requisite separation efficiency (FIG. 4).

The CFD also proved that the particle tracking study for gas-liquid separation revealed that only 98% of liquid droplets carryover of 10 μm will reach the proprietary vane pack.[a] Heavier liquid droplet sizes above 250 μm, separated due to their gravity along the perforated baffle, will not reach the proprietary vane pack[a] and will eventually collect at the bottom of the vessel.

Internals description. The following internals were incorporated in the slug catcher design (FIG. 5) to meet the liquid carryover with gas less than or equal to 0.1 gal/MMsft^3:

1. Feed inlet device: half-cut elbow open pipe at inlet
2. Perforated inlet distribution baffles
3. Proprietary vane pack[a]
4. Axial cyclonic mist eliminator (proprietary horizontal-flow cyclone[b]).

The new feed inlet device induction has a large settling area before the calming baffles. The calming perforated baffles were installed after the inlet nozzle. They ensure proper distribution of gas streams entering the mist eliminator and optimize liquid residence time.

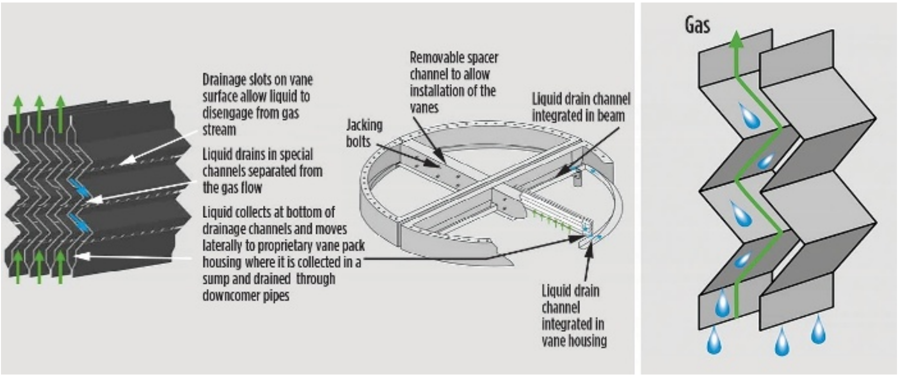

FIG. 7. Simple proprietary vane pack profile with countercurrent drainage of liquid from the vane surface.

The first perforated baffle is a half-diameter baffle, and the second is associated with the proprietary vane pack,[a] as shown in FIG. 6.

The proprietary vane pack preconditioner at the inlet nozzle area is situated on top of the second perforated baffle. The preconditioner ensures the capture of small droplets that coalesce into large droplets, which will further pass with gas entering the cyclone mist eliminator and ensure the removal of small droplets with a cyclone mist eliminator[b] (FIG. 7).

The axial cyclone mist eliminator[b] (FIG. 8) is placed at the gas outlet nozzle. The centrifugal forces of the cyclone combine with the high separation efficiency of the mist eliminator. The mist eliminator combines axial cyclonic and cross-flow separation technology to create an efficient, high-capacity separator.

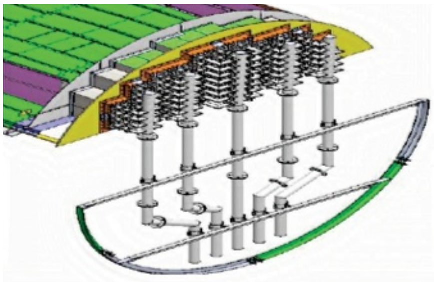

FIG. 8. Cyclone mist eliminator.

Takeaway. A primary concern at the beginning of the Tanajib project was to overcome the perennial problem of separation inefficiencies and fouling issues in slug catchers with conventional mist eliminators. The typical design was ineffective in eliminating the liquid carryover that affected the downstream separation processes at existing plants.

The appropriate internals selected and performance values set for the slug catchers, as discussed in this study, resolved the impacts on the downstream processes. Accurate CFD analysis has proven beyond a doubt that these enhancements to the slug catchers will help avoid fouling issues and associated pressure-drop scenarios affecting unit performance.

The methods and means adopted have created a superior solution to the existing design problem at the Tanajib gas plant, and could provide a retrofit solution for many existing gas plants. **GP**

NOTES

[a] Mellachevron vane pack
[b] VersiSwirl

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Technical and economic impacts of piperazine content in MDEA solvents

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Amine units used in gas and liquid hydrocarbon treating utilize various solvent formulations. Some are amine-based, and some are not. These blended formulations can be open-knowledge or proprietary formulas from a number of different amine suppliers. Usually, these formulations are selected based on a review of the plant design, feed acid gas content (CO_2 and H_2S) and treated gas requirements. In the authors' experience, a considerable number of amine units over-treat or, conversely, are strained to meet specification with the solvent in place. Further evaluation of these units has revealed that modifications to the solvent formulation may result in more ideal treating conditions.

This article discusses the effects of non-ideal amine formulations and the opportunities for reduced costs and improved treating conditions made by reformulating the solvent. A particular case is studied where a formulated methyl diethanolamine (MDEA) solvent was over-treating. An evaluation of several formulations with reduced piperazine concentration was performed to identify formulations that would potentially reduce solvent cost and rich CO_2 loading.

Amine unit background. The amine solvent at a gas plant amine unit (**FIG. 1**) comprised 50% water, 47% MDEA and 3% piperazine. Piperazine is a cyclic diamine used to improve CO_2 removal in MDEA-based solvent formulations. The plant had little trouble meeting specifications for CO_2 content within the range of conditions observed and the formulation in use, but the rich CO_2 loading estimated in the system was above recommended guidelines. The plant engineers wanted to explore a potential reduction in piperazine content in future solvents to reduce amine solvent costs and rich amine CO_2 loading.

The plant was processing up to 90 $MMsft^3d$ of natural gas, but generally bypassing up to 20 $MMsft^3d$ of gas to reduce operational costs while still meeting a 2.5% specification for CO_2 content in the treated gas. The plant normally operates with an amine circulation rate of 190 gal/min (GPM); the design circulation rate is 250 GPM. The operator wanted to decrease piperazine concentration in the amine solvent to reduce both solvent costs and rich loading while staying just under the 2.5% specification. A conditional evaluation was performed to understand if a potential reformulation was feasible and, if so, what conditions must be modified.

The process was evaluated under several sets of conditions with varying MDEA/piperazine formulations to determine the lowest piperazine concentration required to meet specifications. This article summarizes the evaluation work performed, the results and interpretations, and the recommendations for solvent reformulation.

Process simulation overview. A rate-based simulator package[a] was used to evaluate the amine system because of its ability to accurately predict the actual operating conditions and performance of amine gas treating systems. The software package uses a mass transfer rate-based model for column calculations in the amine contactor and regenerator, as opposed to equilibrium stage models used in other simulators. The rate-based model delivers a more accurate prediction of system operation and performance because it takes into account the actual design of the absorber column, as well as its internals.

Equilibrium stage models, by contrast, do not incorporate column design details into the simulation but instead rely on empirical data to estimate reaction kinetics. Equilibrium stage models use ideal stages for column calculations, which do not account for actual tray or packed-bed designs and do not provide a predictive output. The assumptions made for column designs in an equilibrium stage model will be accurate only with empirical data provided for that case, so any modification to the model input will not be simulated accurately without empirical

FIG. 1. Amine system evaluated for solvent reformulation.

data provided for the new conditions.

The objective of the evaluation was to predict operational conditions and performance of the amine system with different amine formulations. The rate-based model was necessary to provide accurate predictions in the absence of any empirical data for potential new formulations. Empirical data for the existing formulation was used to build a base model. That output matched with the empirical data for the treated gas, thereby validating the model accuracy.

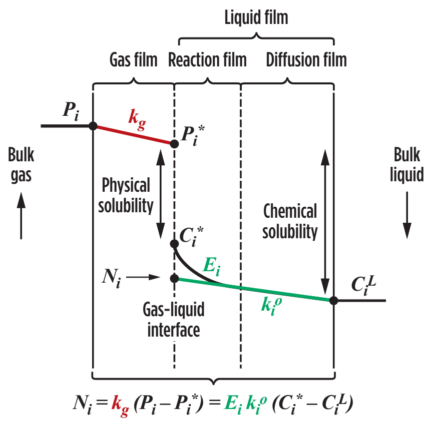

FIG. 2. Diagram representing the various effects contributing to absorption in an amine contactor.[b]

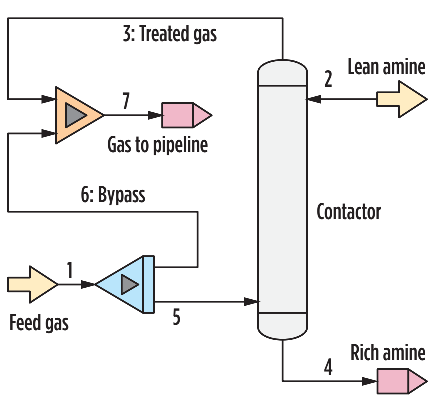

FIG. 3. Process flow diagram of the amine system evaluated.

The Deshmukh-Mather thermodynamic model is used by the software to predict vapor-liquid equilibrium behavior in the system, which is based on the Debye-Huckel theory regarding the behavior of electrolytic solutions. This model predicts the complex interactions involved in amine treating more accurately than conventional equilibrium models.

However, a thermodynamic model alone will not accurately predict amine system operation and performance. A truly predictive model of amine system operation and performance must account for five effects occurring in an absorber or regenerator:

1. Mass and energy balance around phases on each tray (or packing section)
2. Thermodynamic phase equilibrium (this model must be activity-based for the components present and must include an aqueous electrolyte model accounting for chemical reactions)
3. Interfacial equilibrium between phases
4. Chemical kinetics affecting mass transfer rates
5. Mass and heat transfer for components and energy moving across interfaces.

FIG. 2 depicts several aspects involved with acid gas absorption in an amine absorber. The absorption of acid gas components into the amine phase (N_i) depends on the acid gas concentration in both phases relative to the interface ($P_i - P_i^*$ and $C_i^* - C_i^L$), the film mass transfer coefficients (k_g and k_i^o) and the enhancement factor (Ei). The mass transfer coefficients depend on equipment properties such as tray/packing design, fluid properties, and hydraulics. The enhancement factor depends on reaction kinetics and takes diffusion with reaction into account.

Equilibrium stage models account only for mass and energy balances (but only around ideal stages) and thermodynamic phase equilibrium; generally, they do not include an adequate aqueous electrolytic model. Interfacial equilibrium, chemical kinetic effects on mass transfer, and mass and heat transfer for components crossing interfaces are not accounted for.[b]

Simulation design and conditions. To simulate the system properly, normal and worst-case operating conditions for the feed gas and lean amine were collected from historical data. The conditions used for this project are shown in **TABLE 1**.

The full composition of the feed gas was also provided and used in the simulation. In addition, several design drawings and schematics of the amine contactor were collected by plant personnel, and information on the sizing and tray design was incorporated into the simulation. Parameters such as the number of trays, tray spacing, tower diameter, tray and valve type, and tray active area were used as inputs for the simulation.

The simulation PFD is shown in **FIG. 3.** The feed gas composition and process conditions were input into the feed gas block; the amine formulation, amine analysis results and process conditions were input into the lean amine block; and the tower internals information was input into the contactor block. The simulation was then performed, and output data for the rich amine, treated gas and gas-to-pipeline streams were calculated. A feed gas flowrate prior to bypass of 90 MMsft^{3}d was used for the simulation with a bypass flowrate of 10 MMsft^{3}d–20 MMsft^{3}d.

Results and interpretation. Several different scenarios were simulated, using the program, by varying three key parameters:

1. Piperazine concentration
2. Feed gas flowrate
3. Lean amine flowrate.

The objective of the study was to determine if a combined gas-to-pipeline CO_2 specification of 2.5% could be achieved at lower piperazine concentrations, even at worst-case conditions. Piperazine concentrations were varied from 1.5%–3% in different scenarios.

The lean amine flowrate was also varied in each scenario to potentially facilitate a more efficient treating process. In some cases, an increase in amine flowrate can reduce rich loadings to within recom-

TABLE 1. Process conditions used for simulation inputs

Parameter	Value
Feed gas flowrate, MMsft^{3}d	70 (normal)–80 (max.)
Feed gas pressure, psig	860
Feed gas temperature, °F	92–100
Feed gas CO_2 concentration, mol%	4.69
Lean amine flowrate, GPM	190 (normal)–220 (max.)
Lean amine temperature, °F	110–115

mended guidelines (0.5 mol/mol) to prevent corrosion. In other cases, a decrease in amine flowrate can reduce the reboiler duty while maintaining treated gas CO_2 content below specification. The feed gas flowrate to the amine absorber was varied between 70 MMsft³d and 80 MMsft³d, but 70 MMsft³d was targeted to reduce rich loading and reboiler duty.

TABLE 2 shows the results of each scenario that was simulated. The data includes the variable inputs used for each run, as well as the key performance indicators predicted by the simulation output. Values in red were not within recommended guidelines or required specifications.

The normal operational conditions and current solvent were first simulated to validate the accuracy of the model. The treated gas CO_2 content predicted by the simulator matched very closely with that measured at the plant during the same conditions (1.8%). The close match between simulated and actual conditions showed that the model was accurate and that inputs could be modified to reliably simulate real changes at the plant.

The normal operating conditions were also evaluated to understand if the unit could potentially be operated more effectively with the same solvent. The predicted rich loading at base conditions was above the recommended maximum, so the amine flowrate was increased to reduce it. This resulted in higher CO_2 removal and increased reboiler duty, but the reduced rich loading should reduce corrosion. At 80 MMsft³d, the gas-to-pipeline CO_2 specification was still met easily, but the rich loading could not be reduced adequately, even at the higher amine flowrate. This evaluation showed that (1) some corrosion risk is present with the current solvent at normal conditions that can be avoided by increasing amine circulation, and (2) some corrosion risk will inevitably be present at 80 MMsft³d with the current solvent.

The most aggressive scenario simulated was using 1.5% piperazine. This simulation was first performed at a 70-MMsft³d feed gas flow to the contactor and a 220-GPM lean amine flow to understand if enough CO_2 could be removed at the higher bypass rate. The higher bypass rate allows for lower rich loading and is, in general, easier on the amine unit; therefore, lower bypass rates should be avoided when possible. Since the CO_2 content was well over 2.5% in the gas to pipeline, even at increased amine flow, a higher level of piperazine was determined to be necessary. At 2% piperazine, the CO_2 specification was again barely missed in the gas to pipeline.

At 2.35% piperazine, the CO_2 specification was met in the gas to pipeline at 2.46%. Other scenarios were then performed for this formulation. It was determined that at the current amine flowrate, this formulation would not meet the CO_2 specification unless the bypass flowrate was reduced. If the bypass flowrate was reduced, however, the rich loading would increase to above that at present conditions with the present solvent; this essentially showed that this formulation was only feasible and advantageous if the amine flowrate could be increased; otherwise it was more advantageous to remain at 70 MMsft³d to the contactor with the present formulation.

At 2.5% piperazine, the same scenarios were performed as with the 2.35% formulation, and similar results were observed. The amine flowrate needed to be increased for this formulation to work effectively at the higher bypass rate and provide benefit through reduced rich loading.

With the assumption that the amine flowrate could be increased, worst-case scenarios with amine concentration changes, feed gas temperature changes and lean amine temperature changes were then simulated to understand the ability of these solvent formulations to withstand difficult conditions. Scenarios were initially run at higher and lower amine concentrations, since amine is lost over time and must be made up. It was found that treating efficiency decreases at lower concentrations, so several scenarios were performed at 52% water concentration.

TABLE 3 shows the same tests performed as in TABLE 2, but with the total amine concentration reduced by 2% to consider situations where amine is lost and has not yet been made up. It was determined that both the 2.35% and 2.5% formulations were still able to meet CO_2 specification at reduced amine concentration.

TABLE 2. Simulation inputs and key performance indicators predicted by simulation output

Piperazine, wt%	MDEA, wt%	Water, wt%	Feed gas flow, MMsft³d	Lean amine flow, GPM	Weir load, GPM/ft	Treated gas CO_2, mol%	Combined gas CO_2, mol%	Rich CO_2 loading, mol/mol
*3%	*47%	50%	*70	*190	51–53	1.8%	2.46%	0.523
3%	47%	50%	80	190	51–53	1.87%	2.19%	0.583
3%	47%	50%	70	220	59–61	1.71%	2.39%	0.466
3%	47%	50%	80	220	59–61	1.82%	2.15%	0.513
2.5%	47.5%	50%	70	190	51–53	1.87%	2.51%	0.512
2.5%	47.5%	50%	80	190	51–52	1.93%	2.24%	0.573
2.5%	47.5%	50%	70	220	59–61	1.79%	2.45%	0.456
2.5%	47.5%	50%	80	220	59–61	1.88%	2.2%	0.504
2.35%	47.65%	50%	70	190	51–53	1.9%	2.53%	0.509
2.35%	47.65%	50%	80	190	51–52	1.95%	2.26%	0.57
2.35%	47.65%	50%	70	220	59–61	1.81%	2.46%	0.453
2.35%	47.65%	50%	80	220	59–61	1.9%	2.22%	0.501
2%	48%	50%	70	220	59–61	1.87%	2.51%	0.445
1.5%	48.5%	50%	70	220	59–61	1.95%	2.57%	0.434

*Normal operational conditions/current solvent

To further simulate non-ideal conditions for these formulations, the feed gas and lean amine temperatures were also varied. Scenarios were run with these changes at the higher bypass rate and increased amine flowrate, which would provide the most benefit for the unit overall. These cases were also performed at reduced amine concentration to consider the worst-case scenario.

TABLE 4 shows that at elevated feed gas temperature and reduced amine concentration, the 2.35% formulation would not meet CO_2 specification (unless the bypass flowrate is increased). The 2.5% formulation was able to meet specification at elevated feed gas temperature, but only if the amine temperature is maintained; at elevated amine temperature and the other non-ideal conditions specified, the 2.5% formulation just barely misses specification. At the same worst-case conditions, the 3% formulation still met specification at 2.45% CO_2.

Economics and recommendations. A number of potential improvements were discovered in the evaluation results. It was primarily recommended to increase the amine flowrate to ≥ 220 GPM if corrosion in the rich amine circuit was of concern. This would reduce rich loading to levels of acceptable corrosion risk. In addition, the weir load on the trays was low at normal operating conditions, just above the minimum guideline of 50 GPM/ft. Spray flow can occur at low weir loads, leading to reduced treating efficiency and solvent carryover, but an increase in amine circulation could resolve the issue.

The best formulation and conditions for further consideration were chosen by finding a balance between adequate CO_2 removal and rich loading. While several scenarios met specification, most did so at the edge of the high CO_2 specification. The simulations with 2.35%–2.5% piperazine yielded the most ideal results in that both loading and CO_2 content could be maintained comfortably below recommended maximums if the amine flowrate could be increased. Some worst-case conditions emerged where the 2.35%–2.5% formulations did not meet specification at the higher, 20-MMsft^{3}d bypass rate; however, in those situations, the specification can be met by slightly reducing the bypass rate. It follows, then, that more efficient treating would be possible with a reduced piperazine concentration during normal

TABLE 3. Simulation inputs and key performance indicators predicted by simulation (low amine concentration)

Piperazine, wt%	MDEA, wt%	Water, wt%	Feed gas flow, MMsft^{3}d	Lean amine flow, GPM	Weir load, GPM/ft	Treated gas CO_2, mol%	Combined gas CO_2, mol%	Rich CO_2 loading, mol/mol
2.88% *(3%)	45.12% *(47%)	52%	*70	*190	51–53	1.82%	2.47%	0.543
2.88%	45.12%	52%	80	190	51–52	1.89%	2.2%	0.605
2.88%	45.12%	52%	70	220	59–61	1.72%	2.39%	0.485
2.88%	45.12%	52%	80	220	59–61	1.83%	2.15%	0.534
2.4% *(2.5%)	45.6% *(47.5%)	52%	70	190	51–53	1.88%	2.52%	0.532
2.4%	45.6%	52%	80	190	51–52	1.94%	2.25%	0.597
2.4%	45.6%	52%	70	220	59–61	1.79%	2.45%	0.475
2.4%	45.6%	52%	80	220	59–61	1.89%	2.21%	0.524
2.26% *(2.35%)	45.74% *(47.65%)	52%	70	190	51–53	1.9%	2.53%	0.53
2.26%	45.74%	52%	80	190	51–52	1.96%	2.27%	0.592
2.26%	45.74%	52%	70	220	59–61	1.81%	2.47%	0.472
2.26%	45.74%	52%	80	220	59–61	1.91%	2.23%	0.521

*Concentration at 50% water

TABLE 4. Simulation inputs and key performance indicators predicted by simulation (non-ideal conditions)

Piperazine, wt%	MDEA, wt%	Water, wt%	Amine temperature, °F	Feed gas temperature, °F	Weir load, GPM/ft	Treated gas CO_2, mol%	Combined gas CO_2, mol%	Rich CO_2 loading, mol/mol
2.88% *(3%)	45.12% *(47%)	52%	115	100	59–61	1.79%	2.45%	0.474
2.4% *(2.5%)	45.6% *(47.5%)	52%	115	92	59–61	1.81%	2.46%	0.473
2.4%	45.6%	52%	110	100	59–61	1.85%	2.49%	0.466
2.4%	45.6%	52%	115	100	59–61	1.86%	2.5%	0.464
2.26% *(2.35%)	45.74% *(47.65%)	52%	115	92	59–61	1.83%	2.48%	0.47
2.26%	45.74%	52%	110	100	59–61	1.87%	2.51%	0.463
2.26%	45.74%	52%	115	100	59–61	1.89%	2.52%	0.461

*All simulations performed at 70 MMsft^{3}d to the contactor and 220 GPM lean amine

conditions, but at non-ideal conditions the current formulation would work more effectively (to a certain extent).

It was recommended that a formulation with approximately 2.35% piperazine be used if the amine flowrate could be increased to 220 GPM. If the amine flowrate could not be increased, then a 3% formulation would be necessary. The economic implication of reducing the content of piperazine in MDEA solvents based on present market values was, on average, \$0.1/lb–\$0.15/lb (\$0.9/gal–\$1.3/gal) of solvent for each 1% reduction in piperazine. Reducing the piperazine concentration in the present solvent from 3% to 2.35% implied a total savings of \$0.57/gal–\$0.86/gal of MDEA solvent, or \$2,860–\$4,290 for a 5,000-gal inventory. (Note: the data is based on access to market price values).

This study and others have shown that plants can benefit from an evaluation of their amine solvent in place, especially as feed gas compositions change over time. Several standard solvents are sold to plants, but an ideal formulation—prepared based on thorough simulation and evaluation of the amine unit design and operating conditions—is implemented less frequently. Plant personnel should reassess, at least yearly, whether or not such an investigation should be performed with their current amine solvent, as a proper evaluation may reveal opportunities for reduced solvent costs, operating costs, energy usage, corrosion and other cost-effective performance improvements. **GP**

NOTES

[a] ProTreat process simulator package
[b] Based on ProTreat technical literature

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Improve gas turbine operation with a reliability analysis

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Gas turbines require regular maintenance to ensure reliability and consistent performance. When problems are identified during turbine operation or maintenance inspection, significant engineering work is often required to identify and implement an optimal and effective solution.

In this study, the authors present technical data gathered in the field and from the history of an operating gas turbine power plant. These data were used to better assess turbine reliability according to the Weibull distribution and according to maintainability and operating safety availability, as well as to plan preventive maintenance. This application provided an in-depth understanding of the problems encountered, which helped improve the overall reliability of the turbine.

Study aim and outline. Gas turbines have experienced considerable development in many industrial applications in recent years, particularly in power generation. The evolution and success of gas turbines and compressors have been conditioned by improving their technical performance, as well as by improving the availability and maintainability of these machines to optimize their reliability.

Controlling downtime is of utmost importance for any maintenance manager. With this goal in mind, maintenance departments have adopted methods that consider both the technique and organization of turbomachinery maintenance. Maintenance optimization has been achieved with reliability-based maintenance (RBM) and strategies based on failure analysis (the ABC method), as described in this article.[1,2,3]

The aim of this study is to determine the exact maintenance intervals needed for a gas turbine. This determination is based on two main criteria—one that takes into account the number of working hours and the other that considers the number of startups. To this end, a TITAN 130 (T130) gas turbine is studied to assess its performance, maintenance and reliability.

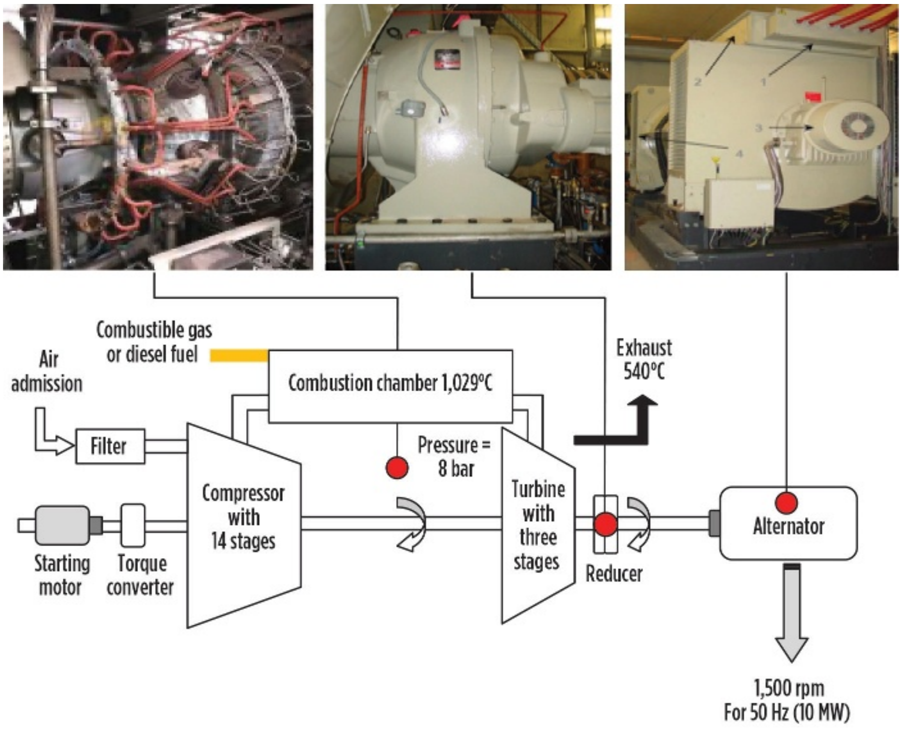

FIG. 1. The working principle of the T130 gas turbine.

The T130 turbine is a single-shaft, self-sustaining system that compresses the atmospheric air in its own compressor, increases the energy power of the air in its combustion chamber and converts this power into useful mechanical energy during the expansion process, which takes place in the turbine section. The resulting mechanical energy is transmitted via a coupling to a receiver, which produces the output power for the industrial process (**FIG. 1**).

In general, the purpose of maintenance is to guarantee the state of good working order of the production tool, thereby ensuring its availability. Maintenance can also help anticipate system failures. To determine the appropriate maintenance policy, it is first necessary to know the reliability of the equipment.

Statistical study of gas turbine failures. The reliability of a gas turbine is evaluated by obtaining information about its components as they relate to events (failures) occurring during the operation or testing of the equipment.

As a first approach to determining reliability, the authors studied the history of functional failures and shutdowns of

the turbine over a 2-yr period. This approach consisted of observing a single gas turbine during a certain time of operation and under real conditions of use, and listing all the failures that arose and the information relating to these failures [e.g., time between failure (TBF), time to repair (TTR) and downtime (DT) due to breakdowns]. This list provided the basic data to quantify the reliability of the gas turbine under study. The authors noted that the gas turbine was stopped 15 times in 2 yr for general cleaning, largely as a result of climate exposure. The three graphs in **FIG. 2** show other preliminary statistics.

In **FIG. 2A**, it is shown that the greatest number of malfunctions occurred between 0 hr and 420.4 hr. Six recorded malfunctions prove that the turbine is going through a difficult stage in terms of good work. In **FIG. 2B,** the repair time represents 8% of the time of good operation, which indicates that the repair team is doing well since it has reached a maximum of 17 hr. Finally, in **FIG. 2C,** a comparison of uptime with repair time shows that the average uptime is decreasing as the repair time increases.

As a preliminary reading of these statistics, the overall system health of this gas turbine is moving closer to the danger zone.

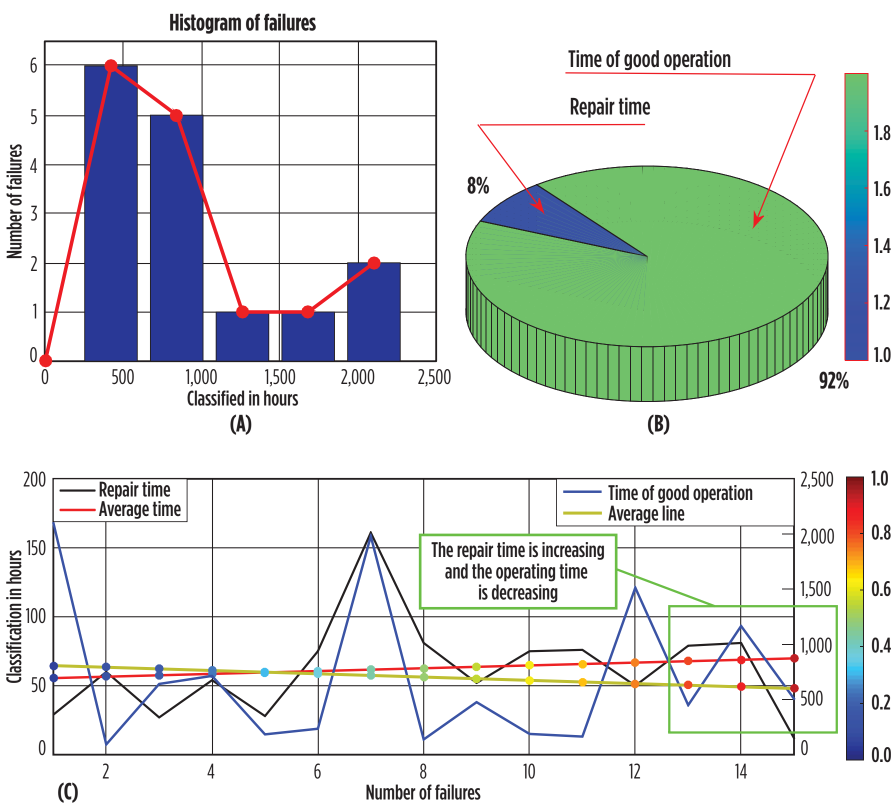

FIG. 2. Different failures by classes (A), percentage of uptime vs. repair time in general (B), and statistics study on the history of breakdowns (C).

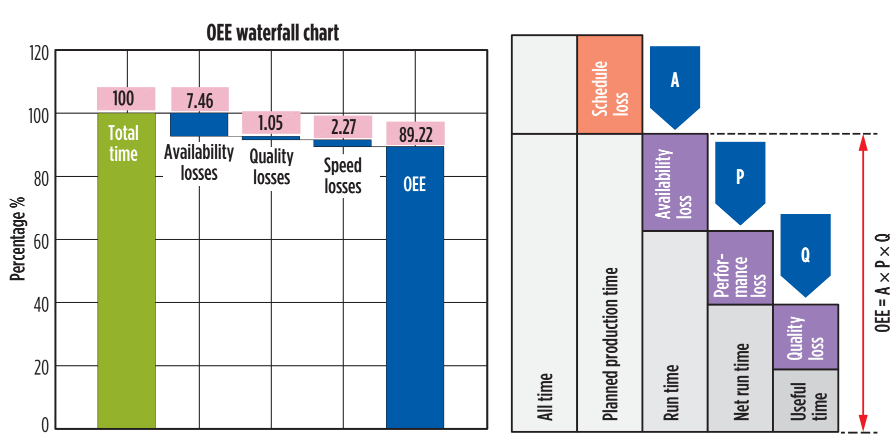

FIG. 3. Cascade diagram of the OEE of the studied gas turbine.

Performance indicators.

Performance is a gold mine, not only for production managers, but also for financiers. Performance indicators allow managers to gain a clear picture of the efficiency of a production unit. The performance strategy focuses on the organization of productive resources to improve the availability of the equipment.

The productivity of equipment is quantitatively monitored by improving the overall equipment effectiveness, or OEE.[4,5,6] The OEE is a composite indicator measuring the occupation of a production resource (machine, line or even a production workshop). It is a ratio, calculated as a percentage from 0% to 100%, with 100% representing fully operational equipment and 0% representing equipment with no operational parts.

During the authors' 2 yr of turbine study, the turbine OEE was found to be low, at between 86.72% and 91.71% (average of 89.22%), mainly due to losses in settings, failures and other shutdowns that negatively influenced equipment performance. The turbine monitoring was based on data collected during this period and used to facilitate the interpretation of OEE tracking results (**FIG. 3**).

Strategy based on reliability.

A reliability analysis strategy (**FIG. 4**) depends on a balanced relationship between predictive and preventive maintenance. The primary goal of reliability analysis is to analyze the behavior of systems based on their failure rate data. These assessments are also useful for planning activities that help improve operational uptime. The most commonly used method is reliability-centered maintenance (RCM).[7,8,9] To implement RCM, the turbine reliability was studied in the context of the Weibull distribution, based on the history of interventions for a limited period of time (14 mos).

The reliability of the gas turbine was estimated using the Weibull model, based on the history of interventions shown in **TABLE 1.** The general form of the reliability function is denoted by $R(t)$, representing the probability of the time between failure at time t (Eq. 1):

$$R(t) = e^{\left(\frac{t-\gamma}{\eta}\right)^{\beta}} \qquad (1)$$

The distribution function, $F(t)$, is the failure probability at t. It is expressed as shown in Eq. 2:

$$F(t) = 1 - R(t) = 1 - e^{\left(\frac{t-\gamma}{\eta}\right)^{\beta}} \qquad (2)$$

The instantaneous rate of failure, $\lambda(t)$, is a reliability estimator. It is expressed as shown in Eq. 3:

$$\lambda(t) = \frac{\beta}{\eta}\left(\frac{t-\gamma}{\eta}\right)^{\beta-1} \qquad (3)$$

The probability density function, $f(t)$, is calculated using Eq. 4:

$$f(t)=\lambda(t) \times R(t)= \frac{\beta}{\eta}\left(\frac{t-\gamma}{\eta}\right)^{\beta-\gamma} \times e^{\left(\frac{t-\gamma}{\eta}\right)} \qquad (4)$$

where η is the scale parameter (dimension of t), γ is the location parameter (dimension of t) and β is the shape parameter (dimensionless).

To calculate the aforementioned parameters, the data must be prepared by first determining the pairs (ti, Fi) by the average (median) ranks, as shown in Eq. 5:

$$F(i) = \frac{\sum ni - 0.3}{N + 0.4} \qquad (5)$$

The real history of the T130 gas turbine is used to calculate and plot the reliability indicators, based on the Weibull distribution. **TABLE 1** shows the data needed to calculate the Weibull parameters.

Results and discussion. The statistical studies, which used the Weibull model and the value of the variable $\beta > 1$, showed that the turbine was heading toward the aging phase. These results could also serve as a diagnosis indicator for maintenance teams to determine the condition of the turbine and predict its future operational state over the short and long terms.

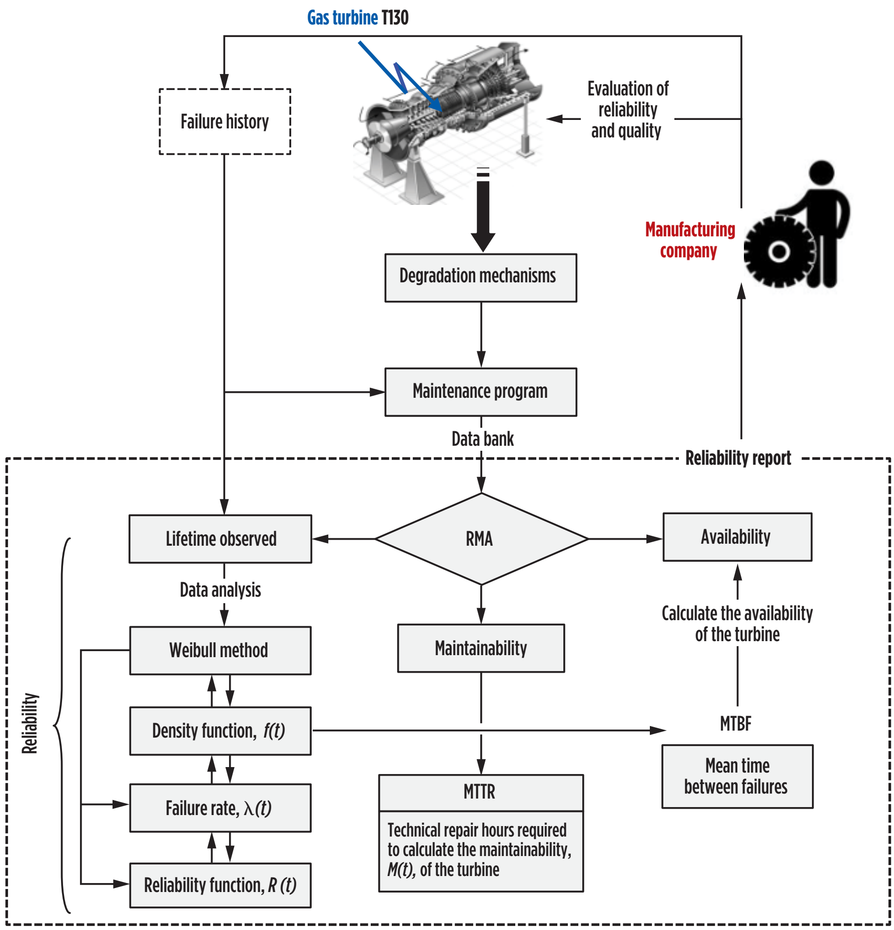

FIG. 4. Method for reliability analysis of the studied gas turbine.

TABLE 1. History of interventions

No. (*N*) of intervention	MTBF, hr	*N*	Σn_i	*F(i)*	*F(t)*	*DN* × max. = [*F(i)* – *F(t)*]
1	93	1	1	0.0454	0.0993	0.0539
2	138	1	2	0.1103	0.1486	0.0383
3	164	1	3	0.1753	0.1764	0.0011
4	184	1	4	0.2402	0.1975	0.0427
5	188	1	5	0.3051	0.2017	0.1034
6	**235**	**1**	**6**	**0.3701**	**0.2497**	**0.1204**
7	449	1	7	0.435	0.4412	0.0062
8	476	1	8	0.5	0.4621	0.0379
9	507	1	9	0.5649	0.4854	0.0795
10	641	1	10	0.6298	0.5759	0.0539
11	714	1	11	0.6948	0.6189	0.0759
12	1,166	1	12	0.7597	0.8073	0.0476
13	1,573	1	13	0.8246	0.8979	0.0733
14	1,980	1	14	0.8896	0.9467	0.0571
15	2,102	1	15	0.9545	0.9563	0.0018

TABLE 2. Reliability results for the studied turbine

MTBF, hr	93	138	164	184	188	235	449	476	507	641	714	1,166	1,573	1,980	2,102
$f(t) \times 10^2$	0.1104	0.1081	0.1062	0.1046	0.1042	0.1	0.0789	0.0763	0.0734	0.0618	0.0561	0.0296	0.161	0.0085	0.007
$F(t)$	0.0993	0.1486	0.1764	0.1975	0.2017	0.2497	0.4412	0.4621	0.4854	0.5759	0.6189	0.8073	0.8979	0.9467	0.9563
$R(t)$	0.9006	0.8514	0.8235	0.8024	0.7982	0.7502	0.5588	0.5378	0.5146	0.4241	0.381	0.1926	0.102	0.0532	0.0437
$\lambda(t) \times 10^2$	0.1225	0.127	0.129	0.1303	0.1306	0.1332	0.1412	0.142	0.1428	0.1458	0.1472	0.1539	0.1581	0.1614	0.1623

TABLE 3. Maintainability results for the studied turbine

Mean TTR, hr	5	12	3	6	4	17	9	2	7
$M(t)$	0.58	0.864	0.394	0.632	0.485	0.943	0.776	0.28	0.688

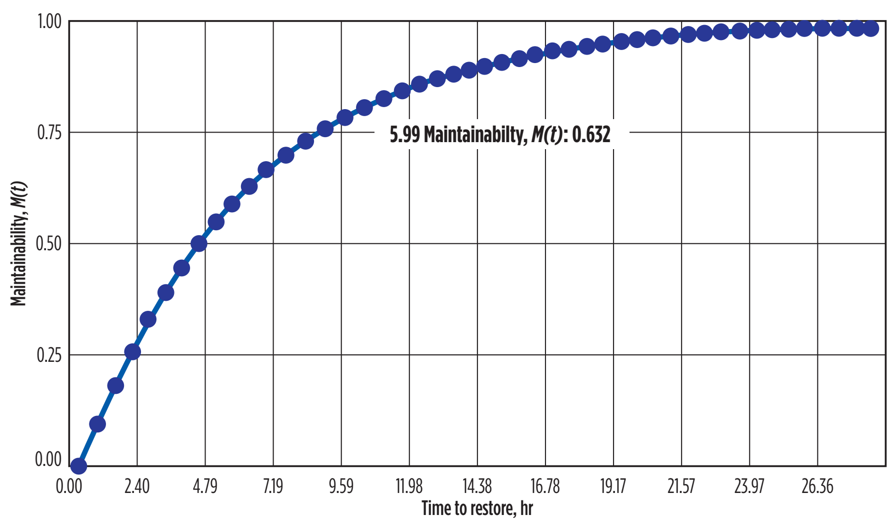

FIG. 5. Estimate of maintainability, using the exponential approximation.

To represent the lifecycle of the studied gas turbine, it is necessary to determine the reliability function, the distribution function, the failure density and the instantaneous failure rate, as illustrated in **TABLE 2.**

The advantage of the failure density function, $f(t)$, is that it shows the distribution of the failures recorded and the mean time between failures (MTBF). For the turbine studied, the probability density increases when the equipment does not exceed $t = 93.59$ and decreases when it exceeds this value. Where the distribution function, $F(t)$, is inversely proportional to the reliability, the obtained results (**TABLE 2**) show that the distribution function rises with the MTBF. This means that the turbine is likely to have significant damages as the time of use increases in the aging phase.

From the perspective of probability, $R(t)$, it is interesting to find the corresponding t in terms of reliability. For a nominal lifetime of L10 associated with the threshold $R(L10) = 0.95$, for the turbine studied it is equal to 771.6591 hr, which means that the systematic intervening time to maintain a reliability of 95% is $t = 771.6591$ hr.

Under the given conditions of use, maintainability is the ability of equipment be maintained or restored to a state where it can perform a required function, when maintenance is performed under given conditions, using prescribed procedures and means. The maintainability of a repairable entity is characterized by a probability, $M(t)$, that the maintenance of an entity, E, performed under given conditions (**TABLE 3**) and with prescribed procedures and means, is completed at time t, knowing that E is at fault time $t = 0$ (Eq. 6):

$$M(t) = 1 - e^{\mu t} \tag{6}$$

where $\mu = 1 \div \text{mean TTR} = 1 \div 6 = 0.166666$ intervention/hr.

The maintainability is shown to be an increasing curve (**FIG. 5**), which complements the unity of the probability and ensures that the system is not repaired on the interval $(0, t)$. From the previous results, the system is shown to be maintainable at 63.2% at $t = 6$ hr.

The availability is shown to be decreasing, and the availability is a reflection of the reliability and maintainability. The change in availability is a direct result of the changes in reliability and maintainability, and the moment of the gas turbine must always act on reliability.

Breakdown analysis of the studied turbine. To apply failure analysis (the ABC method), it is necessary to first make a classification of the failures experienced by the turbine, in descending order of breakdown hours, and then proceed to an ABC Pareto analysis, as shown in **TABLE 4.**

Takeaway. Gas turbines represent a primary equipment link in the oil and gas production chain, and their reliability is a major concern. In this article, the authors presented a numerical study of the reliability of a T130 gas turbine. The study results showed that improvement in the reliability, maintainability and availability of the gas turbine plays a large role in reducing direct and indirect maintenance costs for equipment and, ultimately, for company operations.

This study also helped establish a database of possible unforeseen failures to be used in predictive and preventive maintenance. Predictive testing and inspection techniques make it possible to increase the service life of the turbine and maintain better reliability. The authors offer the following additional recommendations, based on their turbine reliability study:

- Respect the rules of preventive maintenance
- Apply a standard range of maintenance based on manufacturer recommendations

TABLE 4. Instantaneous availability results for the studied turbine

***t*, hr**	10	15	20	25	30	35	40	45	50	55	60	65	70
D(t)	0.193	0.088	0.0427	0.0231	0.0147	0.0111	0.0095	0.0088	0.0085	0.0084	0.0083	0.0083	0.0083

TABLE 5. ABC Pareto analysis of the studied gas turbine

Item	Order of intervention	Nature of intervention	Downtime, hr	Downtime, %	Cumulative downtime, %	Category*
1	5	Problem related to the lubrication circuit	270	31.8	31.8	A
2	8	Problem related to the air circuit	216	25.4	57.2	A
3	7	Problem related to the communication module	90	10.6	67.8	B
4	6	Pump change	72	8.5	76.2	B
5	9	Cleaning	48	5.6	81.9	B
6	4	Sensor change (flame detector)	48	5.6	87.5	C
7	2	Clamping bolts	48	5.6	93.2	C
8	1	Battery change	24	2.8	96	C
9	3	Change of bottles (CO_2)	24	2.8	98.8	C
10	10	Welding at chimney level	10	1.2	100	C
Total			**850**	**100**		

*__Category A:__ Approximately 20% of the causes in this category represent 57.2% of the hr of shadow, which constitutes zone A (problems related to the lubrication circuit and the air circuit)
Category B: Approximately 30% of the causes represent an additional 24.7% (problems related to the communication module, pump and cleaning)
Category C: Approximately 50% of the remaining causes represent only 18.1% of the shutdown hr (change of sensor, tightening of bolts, change of batteries, change of bottles, welding at chimney)

- Check the reliability of other systems with links to turbine equipment. **GP**

ACKNOWLEDGMENTS

This work was supported by the Applied Automation and Industrial Diagnostics Laboratory with the Gas Turbine Joint Research Team at the University of Djelfa in Algeria. The authors express their sincere thanks to the staff of the Menia-Ghardaia power station for their kind hospitality during the realization of this work.

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Natural gas liquids extraction and separation

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Natural gas liquids (NGL) are a group of hydrocarbons, sometimes referred to as purity NGL, that includes ethane, propane, normal butane (n-butane), isobutane and natural gasoline (pentanes plus). NGL made their inroad into fuel markets in the 1910s, when the issue of gasoline loss while stored under normal conditions was addressed, leading to a way to bottle liquid gas.

NGL are produced predominantly in gas processing plants and, to a lesser extent, in refineries as homogeneous liquid blends of purity NGL. The NGL extracted from natural gas make up the so-called Y-grade NGL from which ethane, propane, n-butane, iso-butane and pentanes plus are separated by fractionation in a distillation unit. A subset of NGL is liquid petroleum gas (LPG). LPG is a blend of propane, n-butane and i-butane.

All natural gases contain NGL. Although the quantity of liquids is not always great enough to be economically recovered, there are cases where NGL extraction is desired either to meet sales specifications (minimum and maximum high-heating-value requirements) or to produce transportable gas—i.e., a gas that can be piped without hydrocarbon condensation along the pipeline (dewpoint control).

This article provides an overview of technology for the recovery of NGL, as well as a brief discussion on the economic reasons that justify the extraction of NGL from natural gas and provide the foundation for different processing facility configurations.

Fundamentals of NGL economics. NGL have a wide variety of applications, including feedstock for petrochemical production, as fuel for vehicles and as specialized fuels for space heating and cooking.

Among individual NGL, ethane has the largest share of NGL field production, followed by propane. Together, they make up 90% of the NGL barrel. Ethane is largely used to produce ethylene, the monomer used to produce polyethylene, ethylene oxide, ethylbenzene and dichloromethane, which are raw materials for the production of a wide variety of everyday objects.

Propane is the precursor of polypropylene, which is used to produce plastics, resins, rubbers and other materials. It is also used as a residential and commercial heating fuel, as a drying agent for crops, as a ripening agent for fruit, and so on.

N-Butane is used to produce butadiene, the key component in synthetic rubber. Butane is also used during winter as a fuel additive in motor gasoline. I-Butane is mainly used in refineries as feedstock for the alkylation process to produce alkylate. It is also used in refrigerators, as fuel, and as propellant in cooking spray and hairspray. Pentane is used as a blending fuel in refineries to make motor gasoline, as petrochemical feedstock and as diluent for heavy crudes.

As can be inferred, NGL markets are rather convoluted as they entail five different, volatile markets sharing a common source of supply. Moreover, the transportation and storage of NGL are expensive as they require relatively high pressure and low temperature to be maintained in the liquid state.

Since NGL are mixtures with low density and low viscosity, they can be used as diluent for heavy crude oil so that it can be efficiently transported via pipeline. When the crude oil is worth more than the weighted average value of NGL as gas, the condensate can be used for crude spiking. In doing so, not only are the NGL valued as crude, but also the crude may be upgraded due to the increase of API gravity and sold at a higher price per barrel.

Recovery of NGL might be economically attractive if they are worth more than their value in sales gas; the relative value of liquids against gas is given by the frac spread—i.e., the difference between the NGL market prices and the value of retaining them in the natural gas. Eq. 1 explains how the frac spread is calculated:

$$\text{Frac spread} = \$_l - \$_g \times HHV_{Ci} \times F_i \div 1{,}000{,}000 \quad (1)$$

where:

$\$_l$ = Price of a purity NGL, \$/gal
$\$_g$ = Price of natural gas, \$/MMBtu
HHV_{Ci} = High heating value of the purity NGL, Btu/sft^3

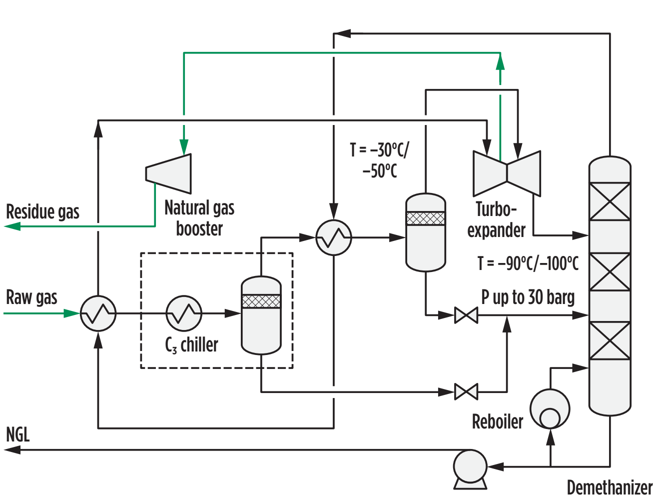

FIG. 1. Turboexpander process flow diagram.

TABLE 1. Frac spread calculation for purity NGL, November 2019

	HHV, Btu, sft³	Volume ratio, sft³/NGL	Value as natural gas, $/gal	Market price, $/gal	Frac spread, $/gal
Ethane	1,770	37.48	0.179	0.198	0.019
Propane	2,516	36.38	0.247	0.52	0.273
i-Butane	3,252	30.64	0.269	0.74	0.471
n-Butane	3,262	31.79	0.28	0.74	0.46

Natural gas price: $2.70/MMBtu (NYMEX, November 2019); purity NGL quotations: Mont Belvieu, November 2019

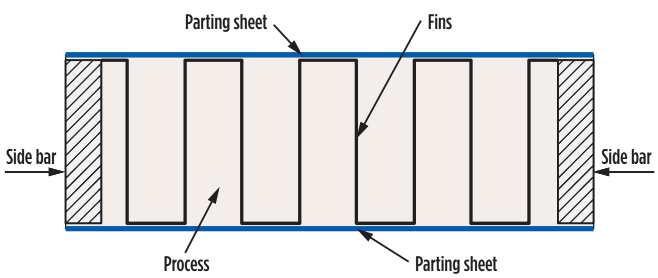

FIG. 2. Key elements of a BAHE.

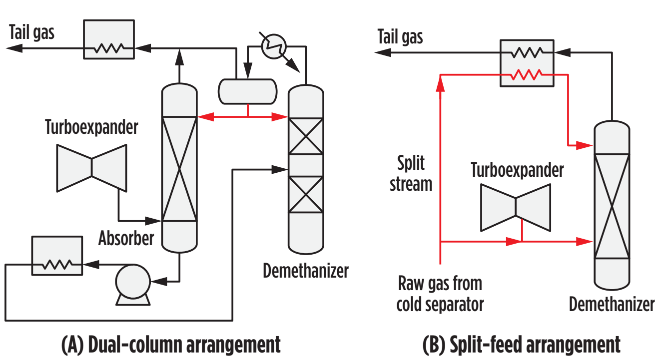

FIG. 3. Dual-column and split-feed arrangements.

F_i = Gas volume to liquid volume conversion ratio.

An example of a frac spread calculation is provided in **TABLE 1.** As shown, in November 2019 the market values of purity NGL in the U.S. exceeded their values as natural gas in the U.S., providing gas processors with an economic incentive to extract C_3+ and reject C_2, since the frac spread of the latter probably does not cover its transportation costs (roughly $0.05/bbl).

The frac spread is a key element of the gas processing plant. However, to achieve effective production planning, other factors must be considered. Among these, the following are spotlighted:

- **Liquid-to-gas ratio.** This ratio is expressed either in gal of liquid per 1,000 ft³ of gas (gal/min) or in m³/MMm³. Generally, a liquid content equal to or greater than 3 gal/min makes NGL recovery profitable.
- **Energy content of raw natural gas.** NGL enter the processing plant as gas and leave as liquid, so less hydrocarbons are left in the gas, which shrinks both in volume and in energy content. The minimum heating value (typically 1,030 Btu/sft³) required for the sale gas may limit the level of NGL that can be extracted from a specific stream of inlet gas, while the dry gas pipeline specification may limit how much ethane can be left in the residue gas.
- **Shrinkage or extraction loss.** The reduction of natural gas value as a result of NGL recovery must be taken into consideration for production configuration decision-making.

If a gas processor finds that ethane recovery is not profitable at a particular time, then the operator will choose to leave ethane in the residue gas (or "tailgate gas"). This operating mode is known as ethane rejection mode.

Since the purity NGL markets are volatile markets, the ethane price may in time rise to a level that makes ethane recovery desirable. The processing plant, therefore, should be designed to be capable of either rejecting ethane when its price is too low or producing ethane when the price is high enough to justify its extraction from raw gas.

Liquid extraction processes. The recovery of Y-grade NGL is typically carried out in a central processing facility at field level; however, not every central processing facility splits NGL into individual components. Sometimes, the Y-grades are delivered to a central fractionation plant (straddle plant) located close to an end market or hub.

The extraction of NGL might be necessary either for meeting the sales gas specification or for producing a gas suitable to be transmitted via pipeline without slug formations (two-phase flows where chunks of liquid hydrocarbons run along the line with a velocity comparable to that of gas). In these cases, the extraction of NGL is done in a hydrocarbon dewpointing process unit.

The process technologies used to carry out an NGL extraction can be categorized into three groups: cryogenic turboexpander recovery technology, mechanical refrigeration and absorption processes. **TABLE 2** provides an overview of the best-known NGL technologies available at present.

Cryogenic turboexpander technologies. The base diagram of a turboexpander process for a rich natural gas is shown in **FIG. 1.** It consists of a cooling train followed by a stabilization column. The condensation of NGL is achieved by combining heat integration and external refrigeration with propane. Methane is stripped from the liquid during ethane extraction in the stabilization section, and ethane is stripped during ethane rejection mode.

The raw gas at high pressure (often 70 barg) is first cooled against the de(m)ethanizer overhead stream, and is then cooled to approximately –40°C in the evaporator of a propane closed-loop refrigeration package. The resulting two-phase flow is separated in the first separator; the liquid is sent to the de(m)ethanizer, and the gas (after further cooling and separation) is expanded, generally to 20 barg–30 barg, in a turboexpander, where its enthalpy variation turns into mechanical work.

The cold two-phase stream from the expander heads to the de(m)ethanizer, where the light components dissolved in the condensate are stripped out according to the operating mode (C_2 extraction or rejection mode). The Y-grade NGL are extracted from the bottom of the de(m)ethanizer and routed to the fractionation section of the facility, while the residue gas is compressed in the compression end of the turboexpander.

Since only a fraction of the mechanical work produced by the expander can be transferred to the compressor, the pressure of the residue gas is significantly lower than that of the raw gas. To feed the downstream pipeline, a booster compressor must be installed to restore the pipeline pressure. The booster compressor is a major consumer of electric power in the process plant. Some processing technology (e.g., Fluor's TCHAP) has been specifically developed to minimize this recompression cost.

It is worth mentioning that in cryogenic service, the most widely used heat transfer equipment is the brazed aluminum heat exchanger (BAHE) or the more recent printed circuit heat exchanger (PCHE). A BAHE is a stack of alternating layers of parting sheets and heat transfer fins. Each layer is provided with inlet and outlet ports for the streams and is sealed along the edge by means of a side bar, as shown in FIG. 2. The block of layers is bounded by cap sheets at the top and bottom and is provided with headers and nozzles for the entrances and exits of process flows.

BAHEs feature a large surface area per unit volume, high heat transfer, a minimum temperature approach as low as 1°C, and the ability to handle multiple process streams. Compared with a shell-and-tube heat exchanger, a BAHE can be 80%–85% smaller and lighter. BAHEs are generally made of aluminum. Since aluminum is prone to mercury corrosion, the use of BAHEs require a mercury removal unit in the pretreatment section of the central processing facility. Moreover, aluminum is a weak material, making BAHEs vulnerable to thermal shocks during startup and shutdown operations.

PCHEs are compact heat exchangers without gaskets, joints or welds. The core of the heat transfer is obtained by means of diffusional bonding, which is a solid state joining process. A number of platelets are stacked in a pile, pressed together, heated at 50%–70% of the material melting point and then allowed to rest so that the material grains can grow and fill the gaps between the surfaces. In doing so, a monolithic block of core heat exchange is obtained. The channels for fluid flow are obtained by chemical etching or pressing.

Designs to accommodate market volatility. When designing central processing facilities for NGL production, processing facilities must be made to accommodate both the ethane extraction and ethane rejection modes to tune the plant operation to market volatility. Rejecting ethane entails a partial loss of propane, which is generally more valuable as a liquid than as natural gas. Therefore, a design goal would be to maximize the propane recovery while ensuring the maximum ethane rejection.

The different ways in which these objectives have been pursued has given rise to different distinctive features of the various processing technologies. The fundamental concepts underlying these different ways can be traced to the basic concepts outlined in the following sections.

Dual column. A dual column consists of the installation of an absorber tower between the turboexpander and the deethanizer (FIG. 3A). A cold, ethane-rich stream coming from the deethanizer is pumped to the top of the absorber, and the bulk of the C_3+ rich stream is extracted from the bottom. Generally, the dual column also entails the dual reflux concept for the bulk removal of NGL in the absorber. In this arrangement, the deethanizer overhead gas is partially condensed, and the liquid is used to reflux both the deethanizer and the absorber towers. In the dual-column, dual-reflux configuration, as much as 99% of propane can be recovered.

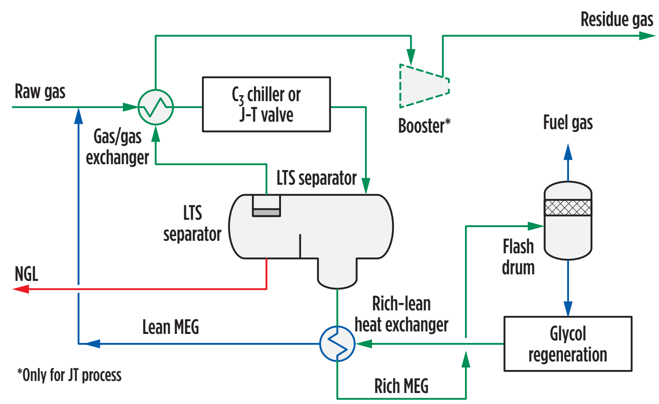

FIG. 4. Simplified PFD of a mechanical refrigeration plant.

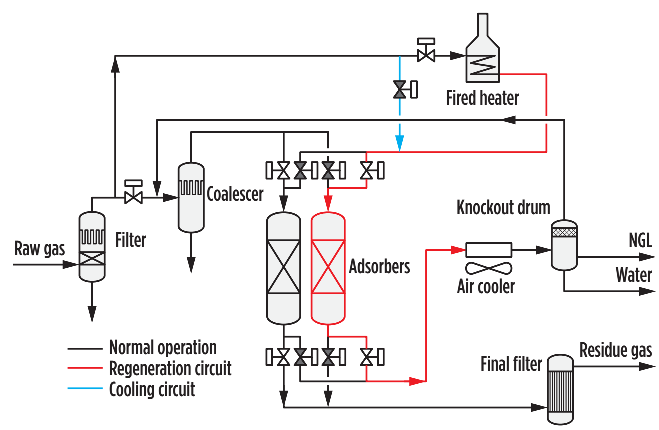

FIG. 5. Process scheme for adsorption on silica gel.

Split-feed gas subcooled process. A slipstream (FIG.3B), typically 15%–30% of the main stream exiting the separators of the cooling train, is subcooled against the cold residue gas and refluxed to the de(m)ethanizer tower (in the case of a single-column arrangement) or to the absorber tower.

Tailgate gas recycle. A slipstream of compressed tailgate gas is cooled in the feed multi-stream plate-fin exchanger, expanded and fed to the top of the de(m)ethanizer. This arrangement improves the C_2+ extraction.

Once the Y-grade NGL have been extracted from natural gas, each purity NGL is obtained by separation of the Y-grade in the fractionation end of the production chain. The fractionation is accomplished by means of a direct sequencing operation of distillation, in which the lightest component is taken overhead in each column. Ethane is first separated from the liquid blend, and then propane, n-butane, iso-butane and natural gasoline are separated in sequence.

TABLE 2. NGL extraction technologies

Commercial name	Processes	Technology provider
Cryogenic turboexpander technology		
CRYOMAX	DCP, MRE, Flex-e	TechnipFMC
High Propane Recovery	HPA, NGL MAX, NGL PRO	McDermott/Lummus Technologies
Gas Subcooled Process, Single Column Overhead Recycle	GSP, SCORE	Ortloff
LPG/C_3+ and NGL/C_2+ recovery and STANDARD line	Cry-Plus, ROC, GSP, RSV	Linde
Cryo-Gas	TCHAP, TRAP, DDP, VRAP, SARD, ERGR	Fluor
Cryogenic process without expander		
Absorption on solvent	AET NGL Rec.	Advanced Extraction Technology
Propane refrigeration cycle		Open art
Iso pressure open refrigeration	IPOR	McDermott/Lummus Technologies
LPG recovery	LPG Plus	Black & Veatch
Joule–Thomson		Open art
Adsorption processes		
Generic adsorption process		Open art
Advanced adsorption process	ADAPT	Siirtec Nigi through DNV GL

Absorption on solvent. In this process, a stream of gasoline (C_5+) is used as solvent for extracting NGL in a regenerative absorption process where the raw gas is contacted counter-currently with a cold lean solvent. The rich solvent drawn from the bottom of the absorber is regenerated in a fractionation tower and recycled back in the absorber. The refrigeration duties required to reflux the columns are provided by a propane refrigeration cycle.

Arguably, this process is less efficient and more expensive relative to the more competitive and simpler expander plant. This explains why few industrial NGL plants are based on this technology.

Mechanical refrigeration. In this process, NGL are partially liquefied by cooling natural gas to a temperature as low as –37°C to –40°C against an evaporating refrigerant fluid, normally propane, in a kettle-type heat exchanger of a closed-loop refrigeration system. Part of the refrigeration duty is recovered in the gas-gas heat exchanger (GGHE), where the raw gas is cooled against the residue gas from the low-temperature separator (LTS) (FIG. 4).

During the cooling step, the gas crosses the hydrate formation envelope and the risk of heat transfer equipment clogging increases; therefore, a hydrate inhibitor must be injected upstream of the GGHE. The inhibitor can be either methanol or glycol—mainly monoethylene glycol (MEG). The former is a relatively volatile chemical; therefore, MEG is generally preferred to methanol. The mechanical refrigeration is, in practice, an isobaric process; therefore, it can be implemented only if the operating conditions fall beneath the cricondenbar.

Joule–Thomson (JT) process. In this process, the gas refrigeration is achieved by exploiting the cooling effect caused by the pressure drop across a throttling valve (JT control valve). The process scheme is similar to that of mechanical refrigeration. Indeed, in the JT process scheme the mechanical refrigerator is replaced with the JT valve.

As the pressure let down is an isoenthalpic and isoenthropic transformation, the final temperature achievable with this process is lower with respect to the external refrigeration, but higher compared to the expander technology. Therefore, the JT process allows the recovery of a greater quantity of NGL than the external refrigeration with propane, but a smaller quantity than the expander.

For tight pressure difference between the raw gas and the residue gas (the majority of cases), the JT process will eventually require the installation of a booster compressor to restore the gas pressure, with sizeable OPEX penalization.

Adsorption on silica gel. Adsorption on silica gel is a separation process (FIG. 5) based on surface chemistry, more specifically on physi-sorption consisting of hydrocarbon and water bonding on hydroxyl groups distributed throughout the surface of the silica gel. Being an amorphous material with mesopores of approximately 20 Å, the pores of the silica gel are also the locus of C_6+ capillary condensation; this characteristic enhances the efficiency of natural gasoline separation.

By increasing the temperature, the interactions between hydrocarbons and silica gel loosen. After all the sorbent hydroxyl groups have been engaged and the bed has become saturated, the adsorbent can be regenerated by heating. Overall, the removal process with silica gel is a dynamic process, where the adsorption stage at temperatures lower than 38°C for a single bed is followed by a regeneration stage at 230°C–270°C.

A silica gel plant consists of at least one fixed-bed column in adsorption mode, one in regeneration mode and one in cooling mode. The continuity of the operation is achieved through sequencing of the columns.

The ADAPT technology utilizes the heat pulse technique, which consists of heating up only a portion of the bed and then exploiting the heat accumulated in this portion to heat up the remaining part of the bed. This technology makes possible the regeneration and cooling in a single column. In doing so, the equipment count and the related, costly cyclic valves and headers are considerably reduced, with sizeable CAPEX savings.

Recently, the ADAPT technology has been extensively implemented for dewpoint control for international transmission of more than 125 Bm^3/yr of natural gas through long, submarine pipelines without intermediate recompression facilities. This process requires deep NGL removal to avoid slug formation in the pipelines. GP

LORENZO MICUCCI is a Senior Director at Siirtec Nigi SpA. He has more than 30 yr of experience in the engineering and contracting industry, most of which have been spent in the natural gas sector. In 2001, he joined Siirtec Nigi in Milan, where he directed the process design and operations department and the research and development department. During his time as R&D head, three patents have been granted to Siirtec Nigi, two of which have been implemented on an industrial scale. At present, he is the Senior Director of the technology and marketing departments. Mr. Micucci also worked for Saipem (Snamprogetti) as a Plant Designer for integrated gasification combined cycle and gas-to-liquids plants. He holds an MS degree in chemical engineering from the University of Bologna in Italy and is enrolled as a Qualified Engineer in the Register of Milan Order of Engineers.

JM to license largest single-train methanol plants

Johnson Matthey (JM) has secured a multiple-license order for China's Ningxia Baofeng Energy Group's project to develop five of the largest single-train methanol plants in the world. Located at Baofeng's Ordos City complex in Inner Mongolia, China, each of the plants will have a planned capacity of 7,200 metric tpd.

Under the agreement, JM will license all five methanol plants and supply associated engineering, technical review, commissioning assistance and catalyst. Using synthesis gas as feed, the methanol plants will use JM radial steam raising converters in a patented Series Loop. JM catalysts will enable Ningxia Baofeng Energy to produce stabilized methanol as a product that is used in the production of olefins.

Brazos Midstream to boost olefins recovery at two cryo plants

Honeywell UOP will upgrade two 200-MMsft^{3}d cryogenic gas processing plants for Brazos Midstream in the Permian Basin, using new technology that can increase recovery of more ethane and propane typically present in natural gas. The upgrade will convert the plants from the gas subcooled process (GSP) to recycle split vapor technology (RSV), developed by its Ortloff Engineers division. Fabrication and assembly of the modular RSV units will be provided by UOP Russell.

The Ortloff RSV2 technology significantly improves the economics of conventional GSP cryogenic gas processing by recycling the gas product to increase the recovery rate of NGL from approximately 92% to nearly 100%. With the upgraded technology, the two plants will be better able to process the NGL-rich gas in Reeves County, Texas. By combining low capital and operating expense and ultra-high NGL recovery rates, the plants can provide significantly better operating margins.

Gasum, UECC conduct first LNG-LBG bunkering

In mid-December 2020, UECC received the first ship-to-ship bunkering of LNG blended with 10% renewable liquefied biogas (LBG). Gasum's LNG bunker vessel, *Coralius,* performed the bunkering operation at anchorage outside the port of Gothenburg, Sweden.

Typically, LBG from Gasum is sourced from biodegradable waste streams in Scandinavia, including residential, retail and commercial sewage and/or agricultural waste streams. The smooth completion of the LNG-LBG bunkering trial will allow ship-to-ship bunkering with different blends of LNG and LBG, which will open new possibilities for decarbonizing Gasum's maritime transport. LBG has a carbon footprint close to zero.

GAS PROCESSING & LNG

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